South Coast
Air Quality Management District
21865 Copley Drive, Diamond Bar, CA 91765-4178
(909) 396-2000 · www.aqmd.gov

DOCKET
05-AFC-3
DATE JAN 2 3 2007
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January 23, 2007

Mr. Robert Worl
Project Manager
California Energy Commission
1516 9th Street, MS 3000
Sacramento, CA 95814-5512

Subject: Sun Valley Energy Project (05-AFC-3) to be located at 29500 Rouse Road, Romoland, CA 92585

Dear Mr. Worl:

This letter is to inform you that the South Coast Air Quality Management District (AQMD) has completed our analysis of the proposed project as described above. Attached for your review is a Preliminary Determination of Compliance (PDOC) that includes the AQMD's engineering analysis.

The proposed facility will be a new major stationary source, and based on the potential to emit the project is subject to EPA review and public notice requirements. Both of these tasks will be undertaken shortly. The final permit to construct is contingent on the CEC approval of the project. In addition, the applicant will be required to obtain emission reduction credits for CO, PM_{10}, VOC, and SOx before the final permit to construct can be issued. Prior to operation of the proposed project, the applicant will be required to obtain sufficient NOx RECLAIM Trading Credits to offset the total facility emissions for the first year of operation.

If you have any questions or wish to provide comments regarding this project, please call Mr. Kenneth L. Coats (kcoats@aqmd.gov) at (909) 396-2527 or Mr. John Yee (jyee@aqmd.gov) at (909) 396-2531.

Very truly yours,

Michael D. Mills

Michael D. Mills, P.E.
Senior Manager
General Commercial & Energy Team
Engineering and Compliance

MDM:MYL:JTY:klc
Attachments

cc: Tom McCabe, Edison Mission Energy

CERTIFIED MAIL
Return Receipt Required

PROOF OF SERVICE (REVISED 1/29/07) FILED WITH
ORIGINAL MAILED FROM SACRAMENTO ON 1/29/07

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT ENGINEERING AND COMPLIANCE DIVISION ENGINEERING ANALYSIS / EVALUATION	PAGES 66	PAGE 1
	APPLICATION NO. 450931 (Master File)	DATE 1-19-2007
	PROCESSED BY: Ken Coats	REVIEWED BY:

SUN VALLEY ENERGY, LLC; ENGINEERING ANALYSIS FOR A NEW 500 MW SIMPLE CYCLE POWER PLANT

COMPANY NAME AND ADDRESS

Sun Valley Energy, LLC
% Edison Mission Energy
18101 Von Karman Avenue
Irvine, CA 92612

Contact: Mr. Thomas J. McCabe, Jr
AQMD Facility ID: 146534

EQUIPMENT LOCATION

29500 Rouse Road
Romoland, CA 92585

EQUIPMENT DESCRIPTION

Section H of the Facility Permit

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions And Requirements	Conditions
Process 1: INTERNAL COMBUSTION					
System 1: GAS TURBINES, POWER GENERATION					
GAS TURBINE, UNIT NO. 1, NATURAL GAS, GENERAL ELECTRIC, MODEL LMS100PA, SIMPLE CYCLE, 904 MMBTU/HR AT 45 DEGREES F WITH WATER INJECTION, WITH A/N 450931 GENERATOR, 104 MW	D1	C3	NOX: MAJOR SOURCE	**CO**: 6.0 PPMV NATURAL GAS (4) [Rule 1303(a)(1)-BACT]; **CO**: 2000 PPMV NATURAL GAS (5) [Rule 407] **NOX:** 15 PPMV NATURAL GAS (8) [40CFR60 Subpart KKKK] **NOX:** 123.46 LB/MMCF NATURAL GAS(1) [Rule 2012] **NOX:** 10.86 LB/MMCF (1) [Rule 2012] **NOX:** 2.5 PPMV NATURAL GAS (4)[Rule 2005-BACT] **VOC:** 2.0 PPMV (4) NATURAL GAS [Rule 1303(a)(1)-BACT] **PM10**: 0.01 GRAIN/DSCF NATURAL GAS (5A) [Rule 475]; **PM10**: 0.1 GRAIN/DSCF NATURAL GAS(5) [Rule 409]; **PM10**: 11 LB/HR NATURAL GAS (5B) [Rule 475] **SOX**: 0.06 LB/MMBTU NATURAL GAS (8) [40 CFR60 Subpart KKKK] **SO2**: (9) Acid Rain Provisions	A63.1, A99.1, A99.2, A99.3, A99.4, A195.1, A195.2, A195.3, A327.1, C1.1, D12.1, D29.1, D29.2, D29.3, D82.1, D82.2, E193.1, H23.1, I296.1, K40.1, K67.1

EQUIPMENT DESCRIPTION (continued)

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions And Requirements	Conditions
Process 1: INTERNAL COMBUSTION					
System 1: GAS TURBINES, POWER GENERATION					
CO OXIDATION CATALYST NO. 1, ENGLEHARD CAMET, 72 CUBIC FEET OF TOTAL CATALYST VOLUME, WITH A/N: 450937	C3	D1 C4			
SELECTIVE CATALYTIC REDUCTION NO. 1, HALDOR-TOPSOE DNX-920, WITH 718 CUBIC FEET OF TOTAL CATALYST VOLUME, HEIGHT: 28 FT 8 IN; WIDTH: 20 FT 3 IN; LENGTH: 1 FT 8 IN; WITH NH3 INJECTION GRID A/N: 450937	C4	C3 S6		**NH3:** 5.0 PPMV (4) [Rule 1303(a)(1)-BACT]	A195.4 D12.2 D12.3 D12.4 E179.1 E179.2 E193.1
STACK NO. 1, DIAMETER: 13 FT 6 IN, HEIGHT: 90 FT A/N: 450931	S6	C4			
GAS TURBINE, UNIT NO. 2, NATURAL GAS, GENERAL ELECTRIC, MODEL LMS100PA, SIMPLE CYCLE, 904 MMBTU/HR AT 45 DEGREES F, WITH WATER INJECTION, WITH A/N 450932 GENERATOR, 104 MW	D7	C9	NOX: MAJOR SOURCE	**CO:** 6.0 PPMV NATURAL GAS (4) [Rule 1303(a)(1)-BACT]; **CO:** 2000 PPMV NATURAL GAS (5) [Rule 407] **NOX:** 15 PPMV NATURAL GAS (8) [40CFR60 Subpart KKKK]; **NOX:** 123.46 LB/MMCF NATURAL GAS (1) [Rule 2012] **NOX:** 10.86 LB/MMCF (1) [Rule 2012] **NOX:** 2.5 PPMV NATURAL GAS (4)[Rule 2005-BACT] **VOC:** 2.0 PPMV NATURAL GAS (4)[Rule 1303(a)(1)-BACT] **PM10:** 0.01 GRAIN/DSCF NATURAL GAS (5A) [Rule 475]; **PM10:** 0.1 GRAIN/DSCF NATURAL GAS (5) [Rule 409]; **PM10:** 11 LB/HR NATURAL GAS (5B) [Rule 475] **SOX**: 0.06 LB/MMBTU NATURAL GAS (8) [40 CFR60 Subpart KKKK] **SO2**: (9) Acid Rain Provisions	A63.1, A99.1, A99.2, A99.3, A99.4, A195.1, A195.2, A195.3, A327.1, C1.1, D12.1, D29.1, D29.2, D29.3, D82.1, D82.2, E193.1, H23.1, I296.1, K40.1, K67.1

EQUIPMENT DESCRIPTION (continued)

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions And Requirements	Conditions
Process 1: INTERNAL COMBUSTION					
System 1: GAS TURBINES, POWER GENERATION					
CO OXIDATION CATALYST NO. 2, ENGLEHARD CAMET, 72 CUBIC FEET OF TOTAL CATALYST VOLUME, WITH A/N: 450938	C9	D7 C10			
SELECTIVE CATALYTIC REDUCTION NO. 2, HALDOR-TOPSOE DNX-920, WITH 718 CUBIC FEET OF TOTAL CATALYST VOLUME, HEIGHT: 28 FT 8 IN; WIDTH: 20 FT 3 IN; LENGTH: 1 FT 8 IN; WITH NH3 INJECTION GRID A/N: 450938	C10	C9 S12		**NH3:** 5.0 PPMV (4) [Rule 1303(a)(1)-BACT]	A195.4 D12.2 D12.3 D12.4 E179.1 E179.2 E193.1
STACK NO. 2, DIAMETER: 13 FT 6 IN, HEIGHT: 90 FT A/N: 450932	S12	C10			
GAS TURBINE, UNIT NO. 3, NATURAL GAS, GENERAL ELECTRIC, MODEL LMS100PA, SIMPLE CYCLE, 904 MMBTU/HR AT 45 DEGREES F WITH WATER INJECTION, WITH A/N 450933 GENERATOR, 104 MW	D13	C15	NOX: MAJOR SOURCE	**CO:** 6.0 PPMV NATURAL GAS (4) [Rule 1303(a)(1)-BACT]; **CO:** 2000 PPMV NATURAL GAS (5) [Rule 407] **NOX:** 15 PPMV NATURAL GAS (8) [40CFR60 Subpart KKKK]; **NOX:** 123.46 LB/MMCF NATURAL GAS (1) [Rule 2012] **NOX:** 10.86 LB/MMCF (1) [Rule 2012] **NOX:** 2.5 PPMV NATURAL GAS (4) [Rule 2005-BACT] **VOC:** 2.0 PPMV NATURAL GAS (4)[Rule 1303(a)(1)-BACT] **PM10:** 0.01 GRAIN/DSCF NATURAL GAS (5A) [Rule 475]; **PM10:** 0.1 GRAIN/DSCF NATURAL GAS (5) [Rule 409]; **PM10:** 11 LB/HR NATURAL GAS (5B) [Rule 475] **SOX:** 0.06 LB/MMBTU (8) NATURAL GAS [40 CFR60 Subpart KKKK] **SO2:** (9) Acid Rain Provisions	A63.1, A99.1, A99.2, A99.3, A99.4, A195.1, A195.2, A195.3, A327.1, C1.1, D12.1, D29.1, D29.2, D29.3, D82.1, D82.2, E193.1, H23.1, I296.1, K40.1, K67.1

EQUIPMENT DESCRIPTION (Continued)

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions And Requirements	Conditions
Process 1: INTERNAL COMBUSTION					
System 1: GAS TURBINES, POWER GENERATION					
CO OXIDATION CATALYST NO. 3, ENGLEHARD CAMET, 72 CUBIC FEET OF TOTAL CATALYST VOLUME, WITH A/N: 450939	C15	D13 C16			
SELECTIVE CATALYTIC REDUCTION NO. 3, HALDOR-TOPSOE DNX-920, WITH 718 CUBIC FEET OF TOTAL CATALYST VOLUME, HEIGHT: 28 FT 8 IN; WIDTH: 20 FT 3 IN; LENGTH: 1 FT 8 IN; WITH NH3 INJECTION GRID A/N: 450939	C16	C15 S18		**NH3:** 5.0 PPMV (4) [Rule 1303(a)(1)-BACT]	A195.4 D12.2 D12.3 D12.4 E179.1 E179.2 E193.1
STACK NO. 3, DIAMETER: 13 FT 6 IN, HEIGHT: 90 FT A/N: 450933	S18	C16			
GAS TURBINE, UNIT NO. 4, NATURAL GAS, GENERAL ELECTRIC, MODEL LMS100PA, SIMPLE CYCLE, 904 MMBTU/HR AT 45 DEGREES F, WITH WATER INJECTION, WITH A/N 450935 GENERATOR, 104 MW	D19	C21	NOX: MAJOR SOURCE	**CO:** 6.0 PPMV NATURAL GAS (4) [Rule 1303(a)(1)-BACT]; **CO:** 2000 PPMV NATURAL GAS (5) [Rule 407] **NOX:** 15 PPMV NATURAL GAS (8) [40CFR60 Subpart KKKK] **NOX:** 123.46 LB/MMCF NATURAL GAS (1) [Rule 2012] **NOX:** 10.86 LB/MMCF (1) [Rule 2012] **NOX:** 2.5 PPMV NATURAL GAS (4)[Rule 2005-BACT] **VOC:** 2.0 PPMV NATURAL GAS (4)[Rule 1303(a)(1)-BACT] **PM10:** 0.01 GRAIN/DSCF NATURAL GAS (5A) [Rule 475]; **PM10:** 0.1 GRAIN/DSCF NATURAL GAS (5) [Rule 409]; **PM10:** 11 LB/HR NATURAL GAS (5B) [Rule 475]; **SOX:** 0.06 LB/MMBTU NATURAL GAS (8) [40 CFR60 Subpart KKKK] **SO2:** (9) Acid Rain Provisions	A63.1, A99.1, A99.2, A99.3, A99.4, A195.1, A195.2, A195.3, A327.1, C1.1, D12.1, D29.1, D29.2, D29.3, D82.1, D82.2, E193.1, H23.1, I296.1, K40.1, K67.1

EQUIPMENT DESCRIPTION (Continued)

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions And Requirements	Conditions
Process 1: INTERNAL COMBUSTION					
System 1: GAS TURBINES, POWER GENERATION					
CO OXIDATION CATALYST NO. 4, ENGLEHARD CAMET, 72 CUBIC FEET OF TOTAL CATALYST VOLUME, WITH A/N: 450940	C21	D19 C22			
SELECTIVE CATALYTIC REDUCTION NO. 4, HALDOR-TOPSOE DNX-920, WITH 718 CUBIC FEET OF TOTAL CATALYST VOLUME, HEIGHT: 28 FT 8 IN; WIDTH: 20 FT 3 IN; LENGTH: 1 FT 8 IN; WITH NH3 INJECTION GRID A/N: 450940	C22	C21 S24		**NH3:** 5.0 PPMV (4) [Rule 1303(a)(1)-BACT]	A195.4 D12.2 D12.3 D12.4 E179.1 E179.2 E193.1
STACK NO. 4, DIAMETER: 13 FT 6 IN, HEIGHT: 90 FT A/N: 450935	S24	C22			
GAS TURBINE, UNIT NO. 5, NATURAL GAS, GENERAL ELECTRIC, MODEL LMS100PA, SIMPLE CYCLE, 904 MMBTU/HR AT 45 DEGREES F, WITH WATER INJECTION, WITH A/N 450936 GENERATOR, 104 MW	D25	C27	NOX: MAJOR SOURCE	**CO:** 6.0 PPMV NATURAL GAS (4) [Rule 1303(a)(1)-BACT]; **CO:** 2000 PPMV NATURAL GAS (5) [Rule 407] **NOX:** 15 PPMV NATURAL GAS (8) [40CFR60 Subpart KKKK]; **NOX:** 123.46 LB/MMCF NATURAL GAS (1) [Rule 2012] NOX: 10.86 LB/MMCF (1) [Rule 2012] **NOX:** 2.5 PPMV NATURAL GAS (4)[Rule 2005-BACT] VOC: 2.0 PPMV NATURAL GAS (4)[Rule 1303(a)(1)-BACT] **PM10:** 0.01 GRAIN/DSCF NATURAL GAS (5A) [Rule 475]; **PM10:** 0.1 GRAIN/DSCF NATURAL GAS (5) [Rule 409]; **PM10:** 11 LB/HR NATURAL GAS (5B) [Rule 475] **SOX:** 0.06 LB/MMBTU NATURAL GAS (8) [40 CFR60 Subpart KKKK] **SO2**: (9) Acid Rain Provisions	A63.1, A99.1, A99.2, A99.3, A99.4, A195.1, A195.2, A195.3, A327.1, C1.1, D12.1, D29.1, D29.2, D29.3, D82.1, D82.2, E193.1, H23.1, I296.1, K40.1, K67.1

EQUIPMENT DESCRIPTION (Continued)

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions And Requirements	Conditions
Process 1: INTERNAL COMBUSTION					
System 1: GAS TURBINES, POWER GENERATION					
CO OXIDATION CATALYST NO. 5, ENGLEHARD CAMET, 72 CUBIC FEET OF TOTAL CATALYST VOLUME, WITH A/N: 450942	C27	D25 C28			
SELECTIVE CATALYTIC REDUCTION NO. 5, HALDOR-TOPSOE DNX-920, WITH 718 CUBIC FEET OF TOTAL CATALYST VOLUME, HEIGHT: 28 FT 8 IN; WIDTH: 20 FT 3 IN; LENGTH: 1 FT 8 IN; WITH NH3 INJECTION GRID A/N: 450942	C28	C27 S30		**NH3:** 5.0 PPMV (4) [Rule 1303(a)(1)-BACT]	A195.4 D12.2 D12.3 D12.4 E179.1 E179.2 E193.1
STACK NO. 5, DIAMETER: 13 FT 6 IN, HEIGHT: 90 FT A/N: 450936	S30	C28			
System 2: EMERGENCY FIRE PUMP					
INTERNAL COMBUSTION ENGINE, EMERGENCY FIRE, DIESEL FUEL, LEAN BURN, CLARKE, MODEL JW6H-UF50, 340 BHP WITH AFTERCOOLER, TURBOCHARGER A/N: 450943	D34		NOX: PROCESS UNIT	**NOX+NMHC:** 4.8 GM/BHP-HR DIESEL (4) [RULE 1303; RULE 2005]; **NOX:** 469 LB/1000 GAL DIESEL (1) [RULE 2012] **CO:** 0.45 GM/BHP-HR DIESEL (4) [RULE 1303] **PM10:** 0.09 GM/BHP-HR DIESEL (4) [RULE 1303] **SOX:** 0.0055 GM/BHP-HR DIESEL (4) [RULE 2005];	B61.1, C1.3, D12.5, D12.6, E193.1, E193.2, I296.2, K67.2
Process 2: INORGANIC CHEMICAL STORAGE					
STORAGE TANK, TK-1, FIXED ROOF, AMMONIA, 19 PERCENT, WITH PRV SET AT A MINIMUM OF 25 PSIG, DIAMETER: 12'-0"; HEIGHT: 12'-0"; 16,000 GALLONS WITH A/N: 451184	D31				C157.1, E144.1, E193.1

Section D of the Facility Permit

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions And Requirements	Conditions
Process 3: RULE 219 EXEMPT EQUIPMENT SUBJECT TO SOURCE SPECIFIC RULES					
RULE 219 EXEMPT EQUIPMENT, COATING EQUIPMENT, PORTABLE, ARCHITECTURAL COATING	E32			VOC: (9) [Rule 1113], [Rule 1171]	K67.3
RULE 219 EXEMPT EQUIPMENT, EXEMPT HAND WIPING OPERATIONS	E33			VOC: (9) [Rule 1171]	

BACKGROUND

In order to pursue the development of a proposed natural gas fired peaker project, Edison Mission Energy (EME) has organized a special purpose entity known as Sun Valley Energy, LLC a Delaware limited liability company, to develop, own and operate the proposed peaker project. Sun Valley Energy, LLC is a wholly-owned subsidiary of EME.

Sun Valley Energy, LLC is proposing to construct a new power plant which will consist of five (5) combustion-turbine-generators (CTGs) for a total rated peak generating capacity of 520 MW at 45°F. The gas turbines will be General Electric LMS100 units. Each turbine will drive a generator rated at 104 MW at 45°F. The project is expected to have an annual capacity factor of approximately 20 to 40 percent, depending on weather-related customer demand, load growth, hydroelectric supplies, generating unit retirements and other factors.

Each of the proposed CTGs will be configured in simple cycle, and therefore there will be no heat recovery steam generators (HRSG), duct burners, or steam turbines used at this plant. The net power generated (after taking away auxiliary power consumption) will be derived solely from the five generators. Selective catalytic reduction (SCR) systems and CO oxidation catalysts will be utilized for control of NOx and CO emissions, respectively. One 16,000 gallon ammonia (NH_3) storage tank will be constructed for the storage of 19% aqueous ammonia which is part of the SCR process. A 5-cell mechanical drift cooling tower will provide heat removal for the gas turbine auxiliary cooling requirements. The site will also employ a 340 bhp diesel emergency fire pump engine.

The California Energy Commission (CEC) has the statutory responsibility for certification of power plants rated at 50 MW and larger, including any related facilities such as transmission lines, fuel supply lines, and water pipelines. The CEC's 12-month, one-stop permitting process is a certified regulatory program under the California Environmental Quality Act (CEQA) and also includes several opportunities for public and inter-agency participation. The CEC's certification process subsumes all requirements of state, local, or regional agencies otherwise required before a new plant is constructed. The CEC coordinates its review of the facility with the federal agencies that will be issuing permits to ensure that the CEC certification incorporates conditions of certification that would be required by various federal agencies. Since the Sun Valley Energy Project (SVEP) will be rated at greater than 50 megawatts, it is subject to the CEC's 12-month certification process. As part of this process, SVEP submitted an application for certification (05-AFC-3) to the CEC on December 1, 2005 seeking certification for the new power plant. In addition to the CEC certification process, SVEP submitted applications to AQMD seeking Permits to Construct for the new power plant. The following table shows the corresponding application numbers (A/Ns):

Table 1 Applications for Permits to Construct Submitted to AQMD

Application Number	Equipment Description
450931	Gas Turbine No. 1
450932	Gas Turbine No. 2
450933	Gas Turbine No. 3
450935	Gas Turbine No. 4
450936	Gas Turbine No. 5
450937	SCR/CO Catalyst for Turbine No. 1
450938	SCR/CO Catalyst for Turbine No. 2
450939	SCR/CO Catalyst for Turbine No. 3
450940	SCR/CO Catalyst for Turbine No. 4
450942	SCR/CO Catalyst for Turbine No. 5
450943	Emergency Fire Pump Engine
451184	Aqueous Ammonia Storage Tank
450866	Initial Title V Application

Each of the applications were submitted to the AQMD on November 30, 2005, except for the application for the NH_3 storage tank, which was submitted on December 9, 2005. AQMD deemed the applications complete on December 13, 2005. Because SVEP will have the potential to generate electricity greater than 25 MW, it will be subject to the federal Acid Rain requirements and therefore the federal Title V permitting requirements apply. SVEP will also be included in the NOx RECLAIM program.

Processing Fee Summary

On November 30, 2005, AQMD received the thirteen (13) applications shown in the table above along with a processing fee of $62,165.76. The $62,165.76 processing fee covers the fees for both the SVEP and another proposed power plant (Walnut Creek Energy Park, aka WCEP) to be located in the City of Industry. The applicant also included a signed form 400-XPP and the appropriate fees for expedited permit processing. The five LMS100s are identical and therefore, four of these devices receive a 50% discount off of the original processing fee of $3,364.77. In addition, the five SCR/CO catalysts are identical and therefore, four of these devices receive a 50% discount off of the original processing fee of $2,437.95. The total fees include the normal processing fees multiplied by 1.5 for expedited processing. A fee summary is shown in the table below.

Table 2 Summary of Processing Fees for SVEP

A/N	Submittal Date	Deemed Complete	Equipment	Schedule	Processing Fee	XPP	TOTAL
450931	11-30-2005	12-13-2005	LMS100 Gas Turbine No. 1	G	$9,459.62	1.5	$14,189.43
450932	11-30-2005	12-13-2005	LMS100 Gas Turbine No. 2	G	$4,729.81	1.5	$7,094.72
450933	11-30-2005	12-13-2005	LMS100 Gas Turbine No. 3	G	$4,729.81	1.5	$7,094.72
450935	11-30-2005	12-13-2005	LMS100 Gas Turbine No. 4	G	$4,729.81	1.5	$7,094.72
450936	11-30-2005	12-13-2005	LMS100 Gas Turbine No. 5	G	$4,729.81	1.5	$7,094.72
450937	11-30-2005	12-13-2005	SCR/CO Catalyst No. 1	C	$2,437.95	1.5	$3,856.93
450938	11-30-2005	12-13-2005	SCR/CO Catalyst No. 2	C	$1,218.98	1.5	$1,828.47
450939	11-30-2005	12-13-2005	SCR/CO Catalyst No. 3	C	$1,218.98	1.5	$1,828.47
450940	11-30-2005	12-13-2005	SCR/CO Catalyst No. 4	C	$1,218.98	1.5	$1,828.47
450942	11-30-2005	12-13-2005	SCR/CO Catalyst No. 5	C	$1,218.98	1.5	$1,828.47
450943	11-30-2005	12-13-2005	Emergency Fire Pump	B	$1,541.34	1.5	$2,312.01
451184	12-7-2005	12-13-2005	Ammonia Storage Tank	A	$1,541.34	1.5	$2,312.01
450866	11-30-2005	12-13-2005	Title V Application	N/A	$1.007.60	N/A	$1.007.60
					TOTAL PROCESSING FEE		$59,370.74

Site Description

The proposed location of SVEP is approximately 0.34 mile north of Rouse Road on the east side of the northerly extension of Junipero Road. The new power plant will be located on an approximately 20-acre parcel (Assessor's Parcel Nos. 331-250-019 and 331-250-020) in Township 5S, Range 3W, Section 14, in Romoland, in an unincorporated parcel of Riverside County. Although the project site is currently in agricultural use, the land is presently zoned for industrial use, with the nearest residence located approximately 0.31 miles from the proposed project site. The site lies southwest of and adjacent to the Burlington Northern Santa Fe (BNSF) rail line which traverses the area in a northwest to southeast direction. The site lies in the area bounded by Matthews Road on the north, Menifee on the east, Palomar Road on the west, and McCall Boulevard to the south. Other residential areas lie to the west, north, and south of the site, with the area to the east of the site being very sparsely populated.

COMPLIANCE RECORD

SVEP is a new facility and construction on the proposed power plant has not yet begun. No additional existing sources are presently operating under the above facility ID. As a confirmation, the AQMD's Compliance Tracking System database indicates no compliance activity for this facility ID.

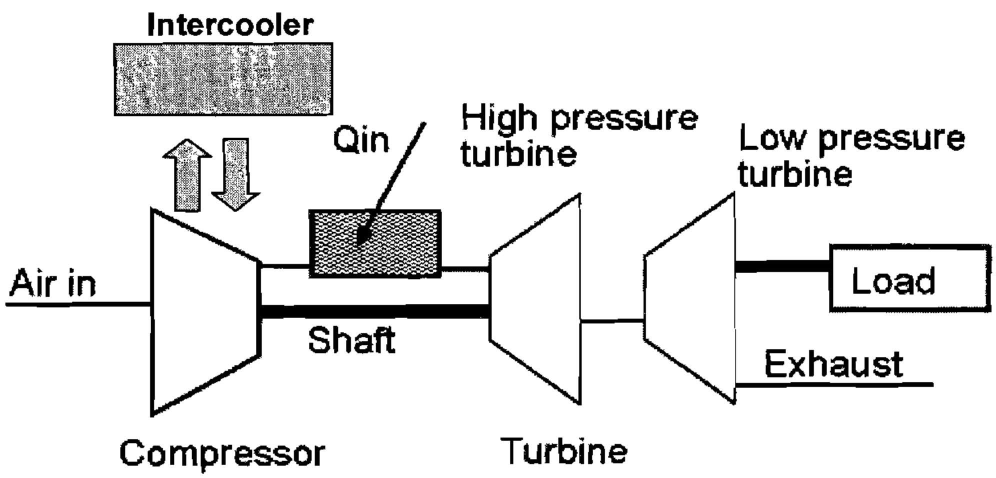
PROCESS DESCRIPTION

The proposed power plant will operate in simple cycle configuration and will employ five (5) General Electric LMS100 combustion gas turbines, each of which employ off-engine intercooling technology with the use of water and an external heat exchanger for increased thermal efficiency. The LMS100 system includes a 3-spool gas turbine configured with an intercooler located between the low-pressure compressor (LPC) and the high-pressure compressor (HPC).

Intercooling

Intercooling provides significant benefits to the Brayton cycle by reducing the work of compression for the HPC, which allows for higher pressure ratios and thereby increasing overall efficiency. For the LMS100, the cycle pressure ratio is 42:1. The reduced inlet temperature for the HPC allows increased mass flow resulting in higher specific power. The lower resultant compressor discharge temperature provides colder cooling air to the turbines, which in turn allows increased firing temperatures equivalent to those of the LM6000, producing an overall cycle efficiency in excess of 46% in simple cycle configuration. This represents a 10% increase in the efficiency over the LM6000. The LMS100 can be configured with two different types of intercooling systems, with the first type being a wet intercooling system which uses an air-to-water heat exchanger (shell and tube design) and an evaporative cooling tower. The second system consisting of bellows expansion joints, moisture separator, variable bleed valve system, and associated piping and involves a dry intercooling system requiring no water. It uses an air-to-air heat exchanger constructed with panels of finned tubes mounted in an A-frame configuration. All five LMS100s proposed for construction at SVEP will be configured with a wet intercooling system. A general diagram of the LMS100 employing wet intercooling technology to be used at SVEP is shown in the diagram below.

LMS100 Gas Turbine with Intercooler



SVEP will connect to Southern California Edison's (SCE) electrical transmission system using a 115kV transmission line. The connection will be made at the Valley Substation, which is located approximately 600 feet north of the proposed project site. Reclaimed water for the cooling tower and evaporative cooler make-up will be supplied by a 12 inch diameter direct connection to a reclaimed water pipeline in a utility easement directly north of the proposed project site. The Eastern Municipal Water District will supply approximately 851 acre-feet/year (ac-ft/yr) of reclaimed water for the project. The following table lists the technical specifications for the General Electric LMS100 CTG.

Table 3 Combustion Turbine Generator Specifications[1]

Parameter	Specifications
Manufacturer	General Electric
Model	LMS100PA[2]
Fuel Type	PUC[3] Quality Natural Gas
Natural Gas Heating Value	1,050 BTU/scf
Gas Turbine Heat Input (HHV)	904 MMBTU/hr at 45°F and 60% relative humidity
Fuel Consumption	0.861 MMSCF/hr[4]
Gas Turbine Exhaust Flow	364,419 DSCFM
Gas Turbine Exhaust Temperature	762°F
Exhaust Moisture	6-8%
Gas Turbine Power Generation	104 MW
Net Plant Heat Rate, LHV	8,061 BTU/kW-hr

[1] Values in this table are on a per-turbine basis
[2] GE manufactures two versions of the LMS100 CTG. SVEP plans to install the LMS100PA. The PA model utilizes water injection for NOx abatement while the PB version utilizes dry low emission (DLE) combustors for NOx abatement.
[3] PUC is the acronym for the California Public Utilities Commission
[4] Represents the maximum possible fuel consumption of the CTG, based on 904 MMBTU/hr heat input and 1,050 BTU/scf fuel heat content. However, the emission calculations will be based on a worst-case operating scenario as identified by the applicant, which may result in a lower fuel usage depending on the ambient temperature, the employment and rate of intercooling, water injection rates, and electrical load generated.

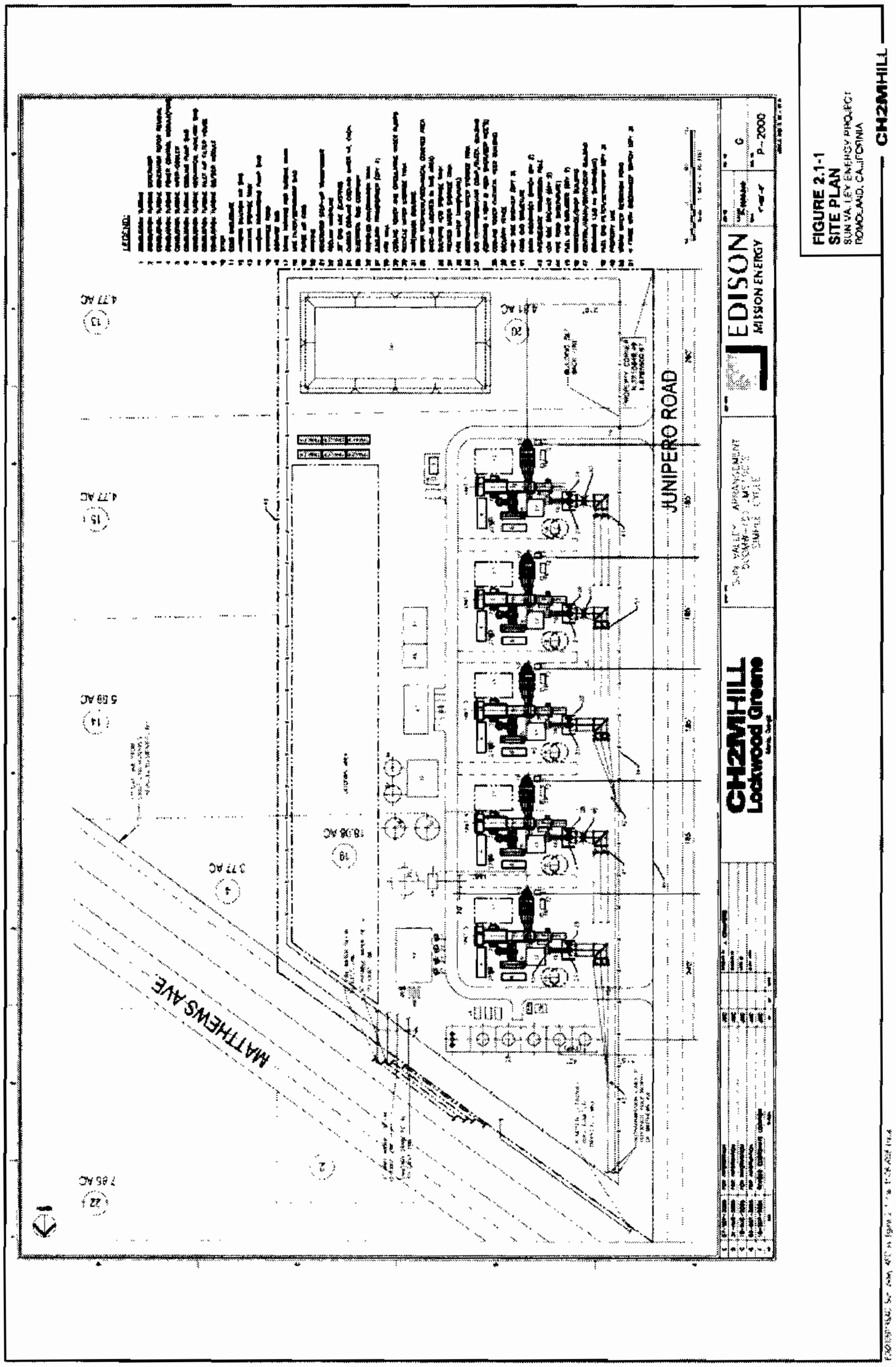


FIGURE 2.1-1
SITE PLAN
SUN VALLEY ENERGY PROJECT
ROMOLAND, CALIFORNIA
CH2MHILL
JUNIPERO ROAD
MATTHEWS AVE
EDISON
MISSION ENERGY
CH2MHILL
Lockwood Greene
LEGEND:

The site plan shown on the previous page was prepared for SVEP by CH2MHILL and shows the general layout of the proposed facility. The five LMS100 CTGs can be seen in the center of the page while the 5-cell cooling tower and circulating water pumps are located to the left of the CTGs. The diagonal line running parallel to Matthews Avenue represents the 12 inch diameter natural gas line which will provide the fuel for the CTGs. The potable water, fire water, and sanitary drain lines are shown in the center of the layout, just to the left of the CTGs.

Definition of a Peaking Unit in Rule 2012

A traditional peaking unit is defined as a turbine which is used intermittently to produce energy on a demand basis and does not operate more than 1,300 hours per year. This definition is found in Rule 2012-Requirements for Monitoring, Reporting and Recordkeeping for Oxides of Nitrogen (NOx) Emissions, Attachment A-F as amended December 5, 2003. SVEP will have the potential to operate for about 3,468 hours/year inclusive of start-up, shutdown, commissioning, maintenance, (if any) and normal operations. Since the annual hours of operation will exceed that which is allowed for a traditional peaking unit under Rule 2012, the LMS100s will not be classified as official peaking units in the equipment descriptions. The CTGs will be listed as NOx Major Sources under Rule 2012.

Air Pollution Control (APC) System

All five CTGs will utilize two primary means for the reduction of NOx emissions. On the front end, SVEP will rely on the use of demineralized water for water injection directly into the CTGs. The demineralized water will be produced by reverse osmosis (RO) and an ion exchange system and will be stored in a 100,000 gallon demineralized water storage tank. The use of demineralized water injection will reduce the 1-hour average NOx concentration to 25 ppmv on a dry basis at 15% O_2 prior to entry to the selective catalytic reduction (SCR) units. On the back end, and SCR catalyst with ammonia injection will be used downstream of each CTG for further reduction of NOx emissions and a CO oxidation catalyst will be used downstream of each CTG for CO emissions reduction. As a result, the NOx emissions will be limited to 2.5 ppmv, 1-hour average, dry basis at 15% O_2. CO emissions will be limited to 6.0 ppmv, 1-hour average, dry basis, at 15% O_2. VOC emissions will be limited to 2.0 ppmv, dry basis at 15% O_2. SOx and PM_{10} emissions will be mitigated through the use of PUC quality natural gas. Detailed descriptions of the air pollution control system are given in the next section. The CO catalyst is permitted together with the SCR catalyst.

Selective Catalytic Reduction/CO Catalyst Systems (A/N 450937, 450938, 450939, 450940, & 450942)

Table 4 shows the specifications for the SCR manufacturer to be used for the simple cycle CTGs.

Table 4 - Selective Catalytic Reduction

Catalyst Properties	Specifications
Manufacturer	Haldor-Topsoe
Catalyst Description	Ti V honeycomb single layer structure
Catalyst Model No.	DNX 920
Catalyst Volume	850 ft^3
Guaranteed Life	Earliest of 20,000 hrs from first gas-in or 51 months from contracted delivery
Space Velocity	23,580 hr^{-1}
Ammonia Injection Rate	190 lb/hr
NOx removal efficiency	>90%
NOx at stack outlet	2.5 ppmv at 15% O_2
Exhaust Temperature	740-800°F

The SCR catalyst will use ammonia injection in the presence of the catalyst to reduce NOx. Diluted ammonia vapor will be injected into the exhaust gas stream via a grid of nozzles located upstream of the catalyst module. The subsequent chemical reaction will reduce NOx to elemental nitrogen (N_2) and water, resulting in NOx concentrations in the exhaust gas at no greater than 2.5 ppmvd at 15% O_2 on a 1-hour average.

CO Oxidation Catalyst
The CO oxidation catalyst will be installed within the catalyst housing which will reduce CO in the exhaust gas to no greater than 6 ppmvd at 15% O_2, on a 1-hour average. The exhaust from each catalyst housing will be discharged from individual 90-foot tall, 13.5 foot diameter exhaust stacks. Each CTG will have its own individual stack.

SVEP has indicated that the CO catalyst manufacturer is to be Englehard. The following table lists the specifications for the CO catalyst. The operating temperature window is between 500°F and 1,250°F.

Table 5 - CO Oxidation Catalyst

Catalyst Properties	Specifications
Manufacturer	Englehard
Model	Camet
Catalyst Type	Pt on Al single layer metal monolith
Catalyst Life	20,000 hours or 5 years
Space Velocity	125,000 hr^{-1}
Volume	200 ft^3
CO removal efficiency	90%
CO at stack outlet	6.0 ppmvd at 15% O_2
Exhaust gas velocity	24 ft/s

Aqueous Ammonia Storage Tank (A/N 451184)
The ammonia will be transported to the site in aqueous form and will have a maximum concentration of 19% by weight. The ammonia will be stored in a specially designated tank with a capacity of 16,000 U.S. gallons with a maximum design pressure of 25 psig, and will be constructed to ASME Section VIII specifications. A vapor return line will be used during receiving operations to control filling losses.

Heated Ammonia Vaporization Skid
The ammonia vaporization skids will be used to vaporize the 19% aqueous ammonia so that it can be transferred to the ammonia injection grids. The ammonia vaporization equipment will be shop-assembled and skid mounted for easy field installation. During cold start-up of the turbine, it will take some time (~10 minutes) before the ammonia injection chamber is hot enough to heat the ammonia for injection. Therefore, each ammonia injection chamber is equipped with an electric pre-heater unit which can be initiated prior to the cold start-ups to ensure that the ammonia is adequately heated prior to injection. The ammonia vaporization skids are typically configured with two dilution air fans (one operating and one spare) and two pre-heater elements (one operating and one spare) housed in a common heater box. In addition, the aqueous ammonia is typically atomized in the ammonia injection chamber and is then fed to the ammonia distribution header.

Ammonia Distribution Header

A carbon steel ammonia distribution header will be used to receive the hot ammonia/air mixture from the ammonia vaporization skid and deliver it evenly to the ammonia injection grid piping. Typically, the injection grid supply piping is equipped with manual butterfly valves and flow instrumentation used for adequate balancing of ammonia flow.

Performance Warranties

Performance warranties for the CO/oxidation and SCR catalysts have been included with the application package and are part of the engineering file. According to the performance warranty[5] for the CO/oxidation catalyst, it will be able to achieve approximately 90% CO reduction from inlet levels of CO. The SCR catalyst will be able to achieve approximately 90% reduction efficiency from inlet levels of NOx and the maximum ammonia slip is warranted to not exceed 5.0 ppmvd at 15% O_2. The table below shows the warranted emissions for NOx, CO, VOC and NH_3 slip.

Table 6 - Warranted Emissions for APC System

Pollutant	Warranted Emissions
Outlet NOx emissions	2.5 ppmv at 15% O_2, dry basis
Outlet CO emissions	6.0 ppmv at 15% O_2, dry basis
Outlet VOC emissions	2.0 ppmv at 15% O_2, dry basis
Ammonia Slip	5.0 ppmv at 15% O_2, dry basis

Cooling Tower System

A 5-cell cooling tower will be included in the proposed design to provide for the gas turbine auxiliary cooling requirements. Two 50% capacity circulating water pumps will provide water to cool three closed-cooling water heat exchangers. The circulating water rate will be 35,500 gallons per minute (GPM). The heat exchangers are each rated at 33% capacity. The closed-cooling water heat exchangers will provide high-quality cooling water to a GE provided pump skid for each CTG. The pump skid will then provide cooling water to the CT compressor intercooler and to the lubrication system. Drift is water entrained by and carried with the air as unevaporated fine droplets. PM_{10} matter is released from a cooling tower through drift. Any solids that are dissolved in the cooling water will be carried out of the tower with the water droplets that are entrained in the air. The water droplet will ultimately evaporate and leave the dissolved solid as PM_{10}. The rate of PM_{10} that is discharged to the atmosphere depends significantly on the drift factor for the cooling tower. The drift factor is the percentage of coolant that leaves through drift with respect to the total flow rate of coolant through the tower. Typical drift rates based on the age of the cooling tower are shown in Table 7 below.

Table 7 - Typical Drift Rates Based on the Age of the Cooling Tower

Year of Construction	Drift Rate as a Percentage of Circulating Water Flow Rate
1970s	0.01%
Early 1980's	0.008%
Mid 1980's	0.005%
1990's	0.002%
2000	0.001%
Current Technology	0.0005%

[5] The performance warranty does not explicitly state an expected conversion efficiency for VOC. However, based on experience with similar turbines, it is expected that at least a 50% reduction efficiency for VOC can result such that VOC emissions at the catalyst outlet can be expected to meet 2.0 ppmvd @ 15% O_2. Therefore, uncontrolled VOC emissions are assumed to be 4.0 ppmvd at 15% O_2, dry basis.

In keeping with current technology, maximum drift loss will be limited to 0.0005% of the circulating water flow. The following table lists the specifications for the cooling tower.

Table 8 - Cooling Tower Specifications

Cooling Tower Parameters	Specifications
Manufacturer	Marley
Number of Cells	5
Exhaust Fan Diameter (ft)	22
Exhaust Flow per Cell (ACFM)	860,100
Circulating Water Rate (GPM)	35,500
Circulating Water Rate (MMlb/hr)	17.74
Fan Exit Height (ft AGL)	39.09

Emergency Fire Pump Engine (A/N 450943)

The fire pump engine will be a diesel fueled Clarke unit, model no. JW6H-UF50. It has a power rating of 340 bhp at 2,100 rpm. The specifications are listed in the table below.

Table 9 - Emergency Fire Pump Specifications

Emergency Fire Pump Parameters	Specifications
Manufacturer	Clarke
Power output	340 bhp at 2,100 rpm
Fuel Consumption	16.0 gal/hr
Exhaust temperature	744°F
Exhaust flow	2,066 ACFM
Stack height	40 ft
Stack diameter	5 in

CRITERIA POLLUTANT EMISSIONS

The total emissions from the power plant will include the summation of all five CTGs, the emergency fire pump engine, and the PM_{10} emissions from the cooling tower. The emissions from the gas turbines are based on the following formula and assumptions:

$$EF(lb/MMBTU) = ppmvd \times MW \times \left(\frac{1}{SMV}\right)\left(\frac{20.9}{5.9}\right) \times F_d$$

where,

ppmvd = Uncontrolled (or controlled) concentration at 15% O_2, dry basis
MW = Molecular weight, lb/lb-mol
SMV = Specific molar volume at 68°F = 385.3 dscf/lb-mol
F_d = Dry oxygen f-factor for natural gas at 68°F = 8,710 dscf/MMBTU

Assumptions:

1. Emissions are based on the worst case operating scenario
2. PM_{10} emissions are based on 0.0067 lb/MMBTU
3. SO_2 to SO_3 conversion in APC equipment is accounted for in the PM_{10} AP-42 emission factor

4. SOx emissions are based on 0.25 grains/100 scf
5. 30-Day Averages are based on 463 hours/month of operation
6. Emissions are based on total fuel consumption rather than total hours of operation

The applicant has identified fifteen possible operating scenarios. The fifteen scenarios are listed as operating conditions (OC)100 through 114 in Section 5 of the applicant's submittal and are summarized in the table below:

Table 10 - Operating Scenarios

	Ambient Temp °F	H_2O Injection, lb/hr	Relative Humidity (%)	Intercooler (on/off)	Compressor Inlet Temp °F
OC100	30	35,385 (100%)	60	On	30
OC101	30	24,795 (70%)	60	On	30
OC102	30	15,760 (45%)	60	On	30
OC103	59	32,449 (92%)	60	On	53
OC104	59	22,235 (63%)	60	On	53
OC105	59	13,945 (39%)	60	On	53
OC106	84	28,325 (80%)	53	On	73
OC107	84	18,872 (53%)	53	On	73
OC108	84	11,031 (31%)	53	On	73
OC109	90	28,389 (80%)	37	On	73
OC110	90	18,917 (53%)	37	On	73
OC111	90	11,074 (31%)	37	On	73
OC112	110	28,408 (80%)	10	On	74
OC113	110	18,932 (54%)	10	On	74
OC114	110	11,527 (33%)	10	On	74

Detail of Operating Conditions

Analysis of the applicant's operating scenarios reveals that GE ran the tests while varying the water injection rate, and compressor inlet temperature. Ambient temperature was allowed to vary from a minimum of 30°F to a maximum of 110°F. Note from the table above that for each ambient temperature, the load was varied between maximum (100%), average (75%), and minimum (50%) loads. The top five cases where fuel flow to the CTGs is the greatest (and therefore yielding the highest emissions) are shown in the table below.

Table 11 - Worst Case Operating Scenario

	Top 5 Operating Conditions				
	100	103	106	109	112
Ambient Temperature, °F	30	59	84	90	110
Ambient Pressure, psia	13.937	13.937	13.937	13.937	13.937
Fuel Consumption, MMBTU/hr	803.3	791.6	748.4	749.5	749.6
Fuel Consumption, lb/hr	38,941	38,373	36,277	36,330	36,337
Exhaust Temperature, °F	761.1	781.6	796.6	796.2	796.1
Load, MW	103.8	101.3	94.2	94.4	94.4
Water Injection (on/off)	On	On	On	On	On
Water Injection, lb/hr	35,385	32,449	28,325	28,389	28,408
Intercooler (on/off)	On	On	On	On	On

Of the top five cases, the worst case scenario occurs during periods of maximum fuel consumption (803.3 MMBTU/hr) at full load (103.8 MW), low ambient temperature (30ºF), with water injection in full use, and the intercooler in operation, as identified in the table above by operating condition no. 100. Therefore, to address the worst case scenario, the facility's NSR emissions will be based on the parameters listed in operating condition no. 100.

There are essentially four modes of operation for the CTGs. Emissions from the four operating modes are distinctly different and must be calculated independently. The following table gives more detail of the four operating modes.

Table 12 - Operating Modes of the CTGs

Mode	Description
Commissioning	The process of fine-tuning each of the CTGs. Facility follows a systematic approach to optimize performance of the CTGs and the associated control equipment. Emissions are expected to be greater during commissioning than during normal operation. This mode affects only the initial year of operation.
Start-up	The applicant has indicated that there will be up to two start-ups per day for each CTG, with each start-up lasting 35 minutes. Start up emissions are higher due to the fact that the control equipment has not reached optimal temperature to begin the chemical reactions needed to convert NOx to elemental nitrogen and water.
Normal Operation	Normal operation occurs after the CTGs and the control equipment are working optimally, at their designated levels, i.e. NOx emissions are controlled to 2.5 ppmvd at 15% O_2, CO emissions to 6.0 ppmv at 15% O_2, and VOC to 2.0 ppmvd at 15% O_2. Emissions may vary due to ambient conditions.
Shutdown	Shutdown occurs at the initiation of the turbine shutdown sequence and ends with the cessation of CTG firing, and will last approximately 11 minutes thereafter. Typically, the shutdown process will emit less than the start-up process but may emit slightly greater than during normal operation because both H_2O injection into the CTGs and NH_3 injection into the SCR reactor have ceased operation

Commissioning Period

Gas turbine commissioning consists of zero load, partial load and full load testing performed immediately after construction for the purposes of optimizing turbomachinery, gas turbine combustors, and optimizing and testing of the SCR/CO catalysts. Several parameters such as water injection rate and degree of SCR and CO control may be varied simultaneously during testing at the discretion of the applicant. Emissions during the commissioning year (usually the first year of operation) may be higher than those during a non-commissioning year due to the fact that the combustors may not be optimally tuned and the SCR/CO catalysts may be only partially operational or not operational at all. The applicant has allocated up to 134 hours of commissioning for each of the 5 CTGs and has further stated that all commissioning will be accomplished within the 9 months prior to initial operation. The commissioning schedule will comprise 6 phases in which the CTGs will be operated at zero, minimum, average and maximum loads while varying the water injection rates and the degree of SCR reactor and CO catalyst control. There will be some cases where the 5 CTGs will be run simultaneously during the commissioning period, and some cases where only one unit may be tested at a time. It will be assumed that the commissioning of the units will be simultaneous to address the worst case scenario. The table below shows the applicant's proposed commissioning schedule along with the cumulative emissions for each of the 5 CTGs during the commissioning period.

Table 13 - Proposed Commissioning Schedule

Commissioning Phase	1	2	3	4	5	6	Totals
Water Injection (% operation)	0	0	50%	100%	100%	100%	
SCR Reactor (% operation)	0	0	0	0	50%	100%	
CO Catalyst (% operation)	0	0	0	0	100%	100%	
Hours per phase	20	14	24	12	24	40	134
Average Load (%)	0%	5%	50%	100%	75%	100%	
NOx (lb/hr)	91	99	175	81	35	8.1	
CO (lb/hr)	55	60	168	255	9	12	
VOC (lb/hr)	2	2	3	5	4	2	
PM_{10} (lb/hr)	1	1	3	6	5	6	
SOx (lb/hr)	0.051	0.061	0.170	0.306	0.238	0.306	
HHV (MMBTU/hr)	150	180	500	900.5	700	900.5	
NOx (lb/mmscf)	641	581	370	95	53	9	
CO (lb/mmscf)	387	352	355	299	14	14	
VOC (lb/mmscf)	14	12	6	6	6	2	
PM_{10} (lb/MMBTU)	0.0066	0.0066	0.0066	0.0066	0.0066	0.0066	
SOx (lb/MMBTU)	0.00068	0.00068	0.00068	0.00068	0.00068	0.00068	
Total NOx lbs, (5 units)	9,100	6,930	21,000	4,860	4,200	1,620	**47,710**
Total CO lbs, (5 units)	5,500	4,200	20,160	15,300	1,080	2,400	**48,640**
Total VOC lbs, (5 units)	200	140	360	300	480	400	**1,880**
Total PM_{10} lbs, (5 units)	100	70	360	360	600	1,200	**2,690**
Total SOx lbs, (5 units)	10.2	12.2	34.0	61.2	47.6	61.2	**226.4**

Start-up / Shutdown of CTGs

The applicant has stated that there will be 350 start-ups and 350 shutdowns per year, with up to 2 start ups per day, with the balance of 2,768 hours left for commissioning and normal operations. According to the applicant, each start-up event is expected to last 35 minutes. During start-up operations, the turbine is assumed to operate at elevated NOx and CO average concentration rates due to the phased-in effectiveness of the SCR reactor and CO oxidation catalysts. Start-ups begin with each turbine's initial firing and continue until each unit complies with the permitted emission concentration limits.

NOx levels are in the 50-100 ppmvd range from the first 3-8 minutes of start-up. Water is injected during the 8^{th} minute of start-up and 25 ppmvd at 15% O_2 is achieved by minute 10 when the unit reaches full load. NOx emissions are further reduced from 25 ppmvd to 2.5 ppmvd over a 30-60 minute period after the CTG achieves full load. CO emissions are assumed to be in the 100-500 ppmvd range for minutes 3 through 10 of start-up. At full load (minute 10), the CO emissions are approximately 100 ppmvd. CO emissions are further reduced from 100 ppmvd to 6 ppmvd over a 30-60 minute period after the CTG achieves full load. GE has provided start-up estimates for the five CTGs and these numbers are included in Appendix A. Shutdowns begin with the initiation of the turbine shutdown sequence and end with the cessation of turbine firing. According to the applicant, each shutdown will last eleven minutes. Upon initiation of the shutdown process, ammonia and water injection will be discontinued. Normal operating emission rates are assumed to occur during the preceding 48 minutes of the shutdown period. GE has provided shutdown estimates for the five CTGs and these numbers are included in Appendix A.

Normal Operations

The emissions during normal operations are assumed to be fully controlled to Best Available Control Technology (BACT) levels, and exclude emissions due to commissioning, start up and shutdown periods, which are not subject to BACT levels. Hourly, monthly, annual, and 30-day averages are calculated and shown in Appendices A through C. The emission calculations for the emergency fire pump and cooling tower are contained in Appendices D and E.

Emissions During A Commissioning Year

The tables below show the cumulative emissions during a commissioning year from all 5 gas turbines which includes commissioning, start-up, shutdown and normal operation, as well as the emissions from the emergency fire pump which is assumed to operate for the designated maximum of 199 hours per year, and the PM_{10} emissions from the 5-cell cooling tower.

Mass Emission Rates, lb/hr (Commissioning Year)

	Emissions, lb/hr					
LMS100PA CTG	NOx	CO	VOC	SO_2	PM_{10}	NH_3
Normal Operations	41.05	60.00	8.55	3.03	30.00	30.35
Start up	52.10	102.00	14.05	3.03	30.00	N/A
Shutdown	55.00	140.00	15.00	3.03	30.00	N/A
Commissioning	356.04	362.99	14.02	1.69	20.07	N/A
Emergency Fire Pump	10.54	0.337	0.112	0.0041	0.067	N/A
5-Cell Cooling Tower	N/A	N/A	N/A	N/A	0.443	N/A
TOTALS	**514.73**	**665.33**	**51.73**	**10.78**	**110.58**	**30.35**

Mass Emission Rates, lb/month (Commissioning Year)

	Emissions, lb/month					
LMS100PA CTG	NOx	CO	VOC	SO_2	PM_{10}	NH_3
Normal Operations	15,105.00	22,080.00	3,146.40	1115.00	11,040.00	11,168.80
Start up	2,084.00	4,080.00	562.00	120.00	1,200.00	N/A
Shutdown	2,200.00	5,600.00	600.00	120.00	1,200.00	N/A
Commissioning	5,340.00	5,445.00	210.75	25.50	300.00	N/A
Emergency Fire Pump	174.79	5.59	1.86	0.07	1.12	N/A
5-Cell Cooling Tower	N/A	N/A	N/A	N/A	128.30	N/A
TOTALS	**24,903.79**	**37,210.59**	**4,521.01**	**1,383.07**	**13,869.42**	**11,168.80**

Mass Emission Rates, lb/year (Commissioning Year)

	Emissions, lb/year					
LMS100PA CTG	NOx	CO	VOC	SO_2	PM_{10}	NH_3
Normal Operations	108,125.00	158,040.00	22,520.00	7,980.00	79,020.00	79,939.42
Start up	18,235.00	35,700.00	4,920.00	1,060.00	10,500.00	N/A
Shutdown	19,250.00	49,000.00	5,250.00	1,060.00	10,500.00	N/A
Commissioning	47,710.00	48,640.00	1,880.00	228.00	2,690.00	N/A
Emergency Fire Pump	2,097.46	67.06	22.35	0.82	13.41	N/A
5-Cell Cooling Tower	N/A	N/A	N/A	N/A	1,539.60	N/A
TOTALS	**195,417.46**	**291,447.06**	**34,592.35**	**10,327.82**	**104,263.01**	**79,939.42**

Emissions During A Non-Commissioning Year

The tables below show the cumulative emissions during a non-commissioning year from all 5 gas turbines which includes, start-up, shutdown and normal operation, as well as the emissions from the emergency fire pump which is assumed to operate for the designated maximum of 199 hours per year, and the PM_{10} emissions form the 5-cell cooling tower.

Mass Emission Rates, lb/hr (Non-Commissioning Year)

	Emissions, lb/hr					
LMS100PA CTG	NOx	CO	VOC	SO_2	PM_{10}	NH_3
Normal Operations	41.05	60.00	8.55	3.03	30.00	30.35
Start up	52.10	102.00	14.05	3.03	30.00	N/A
Shutdown	55.00	140.00	15.00	3.03	30.00	N/A
Emergency Fire Pump	10.54	0.337	0.112	0.0041	0.067	N/A
5-Cell Cooling Tower	N/A	N/A	N/A	N/A	0.443	N/A
TOTALS	**158.69**	**302.34**	**37.71**	**9.09**	**90.51**	**30.35**

Mass Emission Rates, lb/month (Non-Commissioning Year)

	Emissions, lb/month					
LMS100PA CTG	NOx	CO	VOC	SO_2	PM_{10}	NH_3
Normal Operations	15,720.00	22,980.00	3,275.00	1,161.49	11,490.00	11,625.29
Start up	2,084.00	4,080.00	562.00	121.20	1,200.00	N/A
Shutdown	2,200.00	5,600.00	600.00	121.20	1,200.00	N/A
Emergency Fire Pump	174.79	5.59	1.86	0.07	1.12	N/A
5-Cell Cooling Tower	N/A	N/A	N/A	N/A	128.30	N/A
TOTALS	**20,178.79**	**32,665.59**	**4,438.86**	**1,403.96**	**14,019.42**	**11,625.29**

Mass Emission Rates, lb/year (Non-Commissioning Year)

	Emissions, lb/year					
LMS100PA CTG	NOx	CO	VOC	SO_2	PM_{10}	NH_3
Normal Operations	113,626.40	166,080.00	23,666.40	8,387.00	83,040.00	83,945.03
Start up	18,235.00	35,700.00	4,920.00	1,060.00	10,500.00	N/A
Shutdown	19,250.00	49,000.00	5,250.00	1,060.00	10,500.00	N/A
Emergency Fire Pump	2,097.46	67.06	22.35	0.82	13.41	N/A
5-Cell Cooling Tower	N/A	N/A	N/A	N/A	1,539.60	N/A
TOTALS	**153,208.86**	**250,847.06**	**33,858.75**	**10,507.82**	**105,593.01**	**83,945.03**

30-Day Averages

The 30 Day Average emissions are calculated in Appendix B for both a commissioning and non-commissioning year for the worst case operating scenario. The worst case operating scenario was defined as OC100 in Table 11 above. The values in the tables below are the cumulative 30 day averages for the entire facility (5 CTGs, the emergency fire pump and the cooling tower).

Cumulative 30-Day Averages, lb/day (Commissioning Year)

	30 Day Average, lb/day				
Five LMS100PA CTGs	NOx[6]	CO	VOC	SOx	PM_{10}
Normal Operations		736	105	37	368
Start up		136	19	4	40
Shutdown		187	20	4	40
Commissioning		181	7	1	10
One Emergency Fire Pump[7]		0	0	0	0
One 5-Cell Cooling Tower		N/A	N/A	N/A	(4)[8]
TOTALS		**1,240**	**151**	**46**	**458**

Cumulative 30-Day Averages, lb/day (Non-Commissioning Year)

	30 Day Average, lb/day				
Five LMS100PA CTGs	NOx[6]	CO	VOC	SOx	PM_{10}
Normal Operations		766	109	37	383
Start up		136	19	4	40
Shutdown		187	20	4	40
One Emergency Fire Pump[7]		0	0	0	0
One 5 Cell Cooling Tower		N/A	N/A	N/A	(4)[8]
TOTALS		**1,089**	**148**	**45**	**463**

The following is a comparison of the cumulative 30-day averages for the entire facility (5-LMS100 PA gas turbines, 1-emergency fire pump, and 1-cooling tower) for both a commissioning year and a non-commissioning year. The maximum 30-day averages for each pollutant, shown in bold.

	NOx[6]	CO	VOC	SOx	PM_{10}
30 Day Average (Commissioning Year)		**1,240**	**151**	**46**	458
30 Day Average (Non-Commissioning Year)		1,089	148	45	**463**

The following table shows the 30-day averages from one individual LMS100PA gas turbine for both a commissioning year and a non-commissioning year. The maximum 30-day averages for each pollutant are shown in bold.

	NOx[6]	CO	VOC	SOx	PM_{10}
30 Day Average (Commissioning Year)		**248**	**30**	**9**	92
30 Day Average (Non-Commissioning Year)		218	30	9	**93**

[6] SVEP has elected to enter RECLAIM. As such, RECLAIM Trading Credits (RTC) will be used to satisfy the NOx offsetting requirements of Rule 2005, and therefore the 30-Day Averages for NOx need not be calculated

[7] The emergency fire pump is exempt from offsets (and modeling) under Rule 1304(a)(4)-Emergency Equipment if operated < 200 hr/yr

[8] The cooling tower is exempt from requiring a permit under Rule 219(e)(3) and consequently it is exempt from NSR. Therefore, offsets are not required for the cooling tower

PROHIBITORY RULE EVALUATION

RULE 212-Standards for Approving Permits

Rule 212 requires that a person shall not build, erect, install, alter, or replace any equipment, the use of which may cause the issuance of air contaminants or the use of which may eliminate, reduce, or control the issuance of air contaminants without first obtaining written authorization for such construction from the Executive Officer. Rule 212(c) states that a project requires written notification if there is an emission increase for ANY criteria pollutant in excess of the daily maximums specified in Rule 212(g), if the equipment is located within 1,000 feet of the outer boundary of a school, or if the MICR is equal to or greater than one in a million (1EE-6) during a lifetime (70 years) for facilities with more than one permitted unit, source under Regulation XX, or equipment under Regulation XXX, unless the applicant demonstrates to the satisfaction of the Executive Officer that the total facility-wide maximum individual cancer risk is below ten in a million (10EE-6) using the risk assessment procedures and toxic air contaminants specified under Rule 1402; or, ten in a million (10EE-6) during a lifetime (70 years) for facilities with a single permitted unit, source under Regulation XX, or equipment under Regulation XXX. The total facility wide residential MICR is expected to be less than 1EE-6. However, since the emissions of criteria pollutants for the facility exceed the thresholds in Rule 212(g), a public notice is required in accordance with the requirements of Rule 212. A public notice will be issued followed by a 30-day public comment period prior to issuance of a permit.

FACILITY / EQUIPMENT AND SCHOOL LOCATIONS

This proposed project is located at 29500 Rouse Road, Romoland, which is in an unincorporated part of Riverside County. Schools located nearest to the facility are at least a minimum of 0.37 miles away from the proposed project site as measured by the Mapquest program found at http://www.google.com.

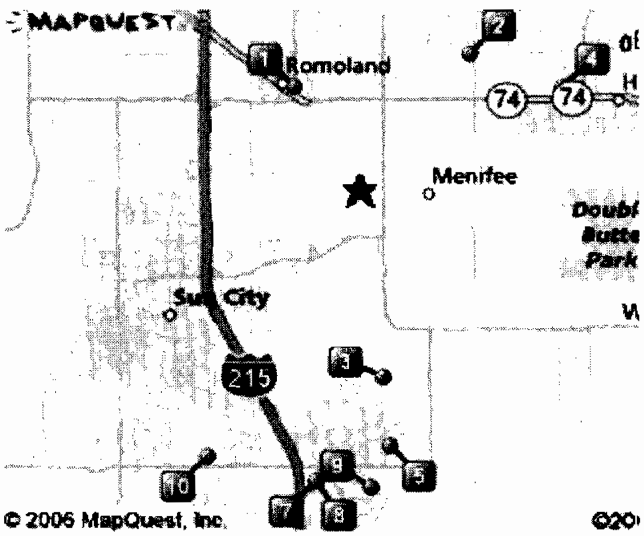
As an alternate means of determining the sensitive receptor distance from the proposed site, latitude/longitude coordinates were collected at the proposed site as well as the closest sensitive receptors using a digital camera equipped with a GPS receiver. The receptor coordinates were then converted to distances, measured in feet, from the proposed site. The following table shows the distance from SVEP to each sensitive receptor as measured by (1) Mapquest and (2) using GPS coordinates (fenceline-to-fenceline)

Name of School	Address	Mapquest Distance Miles (feet)	GPS Distance (feet)
1. Romoland Elementary School	25800 Antelope Rd, Romoland	1.37 (7,234)	5,566
2. Harvest Valley Elementary School	29955 Watson Rd, Sun City	1.97 (10,402)	8,030
3. Freedom Crest Elementary School	29282 Menifee Rd, Menifee	2.06 (10,877)	12,174
4. Romoland School District	25900 Leon Rd, Homeland	2.58 (13,622)	Not Measured
5. Menifee Elementary School	30205 Menifee Rd, Menifee	2.82 (14,890)	17,396
6. Simily's (Private School)	P.O. Box 514, Homeland	3.21 (16,949)	Not Measured
7. H&R Block (Private School)	30141 Antelope Rd, Menifee	3.24 (17,107)	Not Measured
8. Tri-City SDA Elementary School	30141 Antelope Rd, Menifee	3.26 (17,213)	Not Measured
9. Kirkpatrick Elementary School	28800 Reviere Dr, Menifee	3.26 (17,213)	Not Measured
10. Tri-City Adventist School	29885 Bradley Rd, Sun City	3.38 (17,846)	Not Measured
11. Boulder Elementary School[9]	27327 Junipero Rd, Romoland	N/A	2,975

Each of the sensitive receptors are located at distances greater than 1,000 feet from the proposed SVEP site, as verified by both Mapquest and GPS coordinates.

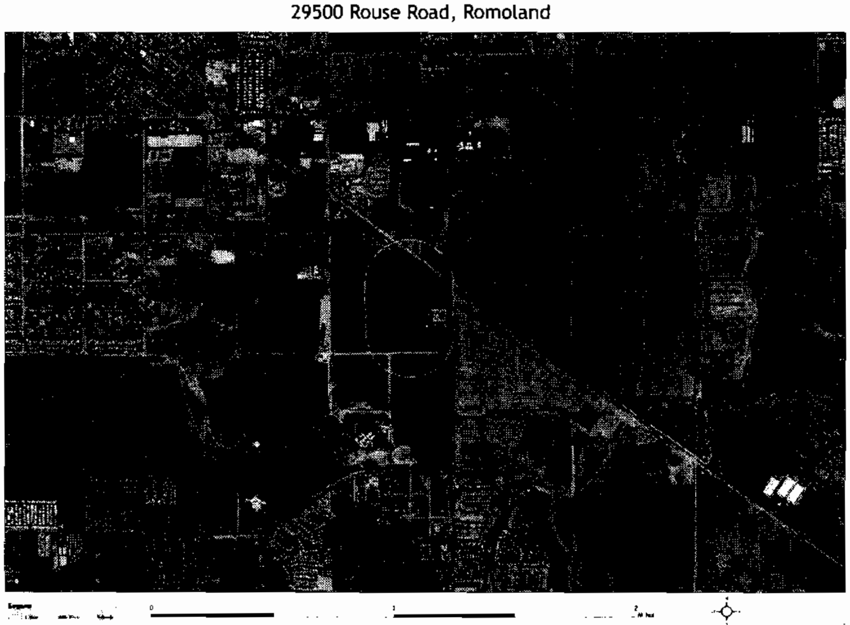
[9] This school is not depicted on Mapquest as of October 12, 2006.

The map below is a graphical representation of the surrounding vicinity of the proposed SVEP site, which includes the locations of the sensitive receptors enumerated 1-10 below. The proposed project site is therefore not located within 1,000 feet of the outer boundary of a school.



Below is an aerial shot of the surrounding vicinity of the proposed Sun Valley Energy Project. The inner circle depicts the area within 1,000 feet from the proposed site. The larger circle represents an area within 1 mile of the proposed site.

Sun Valley Energy Project
29500 Rouse Road, Romoland



RULE 401-Visible Emissions

This rule limits visible emissions to an opacity of less than 20 percent (Ringlemann No.1), as published by the United States Bureau of Mines. It is unlikely, with the use of the SCR /CO catalyst configuration that there will be visible emissions. However, in the unlikely event that visible emissions do occur, anything greater than 20 percent opacity is not expected to last for greater than 3 minutes. During normal operation, no visible emissions are expected. Therefore, based on the above and on experience with other CTGs, compliance with this rule is expected.

RULE 402-Nuisance

This rule requires that a person not discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which cause, or have a natural tendency to cause injury or damage to business or property. The new turbine will be operated in a fairly remote (non-residential) area of San Bernardino County and is not expected to create a public nuisance based on experience with identical CTGs. Therefore, compliance with Rule 402 is expected.

RULE 403-Fugitive Dust

The purpose of this rule is to reduce the amount of particulate matter entrained in the ambient air as a result of man-made fugitive dust sources by requiring actions to prevent, reduce, or mitigate fugitive dust emissions. The provisions of this rule apply to any activity or man-made condition capable of generating fugitive dust. This rule prohibits emissions of fugitive dust beyond the property line of the emission source. The applicant will be taking steps to prevent and/or reduce or mitigate fugitive dust emissions from the project site. Such measures include covering loose material on haul vehicles, watering, and using chemical stabilizers when necessary. The installation and operation of the CTGs is expected to comply with this rule.

RULE 407-Liquid and Gaseous Air Contaminants

This rule limits CO emissions to 2,000 ppmvd and SO_2 emissions to 500 ppmvd, averaged over 15 minutes. For CO, the CTGs will meet the BACT limit of 6.0 ppmvd at 15% O_2, 1-hr average, and the turbine will be conditioned as such. For SO_2, equipment which complies with Rule 431.1 is exempt from the SO_2 limit in Rule 407. The applicant will be required to comply with Rule 431.1 and thus the SO_2 limit in Rule 407 will not apply.

RULE 409-Combustion Contaminants

This rule restricts the discharge of contaminants from the combustion of fuel to 0.23 grams per cubic meter (0.1 grain per cubic foot) of gas, calculated to 12% CO_2, averaged over 15 minutes. The equipment is expected to meet this limit based on the calculations shown below:

Estimated exhaust gas	364,419 DSCFM = 21.87 mmscf/hr
Maximum PM10 Emissions	6 lb/hr
Estimated CO2 in exhaust	3%

$$\text{Grain Loading} = \frac{(6\ \text{lb/hr})(7000\ \text{gr/lb})}{21.87\text{EE}6\ \text{scf/hr}} \times \frac{12}{3} = 0.00768\ \text{gr/dscf} << 0.1\ \text{gr/dscf}$$

RULE 431.1-Sulfur Content of Gaseous Fuels

SVEP will use pipeline quality natural gas which will comply with the 16 ppmv sulfur limit, calculated as H2S, specified in this rule. SVEP has provided a gas analysis which demonstrates the natural gas has a sulfur content of less than 0.25 gr/100scf, which is equivalent to a sulfur concentration of about 4 ppmv. It is also much less than the 1 gr/100scf limit typical of pipeline quality natural gas. Compliance is expected.

RULE 474-Fuel Burning Equipment-Oxides of Nitrogen

Superseded by NOx RECLAIM.

RULE 475-Electric Power Generating Equipment

This rule applies to power generating equipment rated greater than 10 MW installed after May 7, 1976. Requirements specify that the equipment must comply with a PM_{10} mass emission limit of 11 lb/hr or a PM_{10} concentration limit of 0.01 grains/dscf. Compliance is demonstrated if either the mass emission limit or the concentration limit is met. The PM_{10} mass emissions from the SVEP turbines is estimated to be 6 lb/hr. The estimated grain loading is less than 0.01 grain/dscf (see calculations under Rule 409 analysis). Therefore, compliance is expected. Compliance will be verified through performance tests.

NEW SOURCE REVIEW (NSR) ANALYSIS

The following section describes the NSR analysis for SVEP. The facility can comply with NSR either by qualifying for various exemptions from or by demonstrating compliance with the following rules. Since SVEP is a new facility, there are no exemptions from any portions of NSR. Therefore each of the following NSR rules will apply. Each piece of equipment at SVEP is evaluated for compliance with the rules in the table below.

Table 14 - Applicable NSR Rules for SVEP

Applicable NSR Rules for Non-RECLAIM Pollutants (CO, SOx, VOC, PM_{10})	Applicable NSR Rules for RECLAIM Pollutants (NOx)
Rule 1303(a)-BACT	Rule 2005(b)(1)(A)-BACT
Rule 1303(b)(1)-Modeling	Rule 2005(b)(1)(B)-Modeling
Rule 1303(b)(2)-Offsets	Rule 2005(b)(2)-Offsets
Rule 1303(b)(3)-Sensitive Zone Requirements	Rule 2005(e)-Trading Zone Restrictions
Rule 1303(b)(4)-Facilitywide Compliance	Rule 2005(g)-Additional Requirements
Rule 1303(b)(5)-Major Polluting Facilities	Rule 2005(h)-Public Notice
Rule 1309.1 - Priority Reserve	Rule 2005(i)-Rule 1401 Compliance
	Rule 2005(j)-Compliance with Fed/State NSR

RULE 1303(a) and Rule 2005(b)(1)(A)-BACT – LMS100 CTGs

These rules state that the Executive Officer shall deny the Permit to Construct for any new source which results in an emission increase of any non-attainment air contaminant, any ozone depleting compound, or ammonia unless the applicant can demonstrate that BACT is employed for the new source. SVEP is a new source with a potential for an increase in emissions and therefore, BACT is required. Each of the LMS100 CTGs proposed for construction by SVEP will be operated on a simple cycle (no steam turbine, HRSG, or secondary electrical generator is associated with simple cycle configurations). As of the date of this evaluation, BACT for simple cycle gas turbines is shown in Table 15 below:

Table 15 - BACT Requirements for Simple Cycle Gas Turbines

NOx	CO	VOC	PM_{10}/SOx	NH_3
3.5 ppmvd, at 15% O_2, 3-hour rolling average	6.0 ppmvd, at 15% O_2, 3-hour rolling average	2.0 ppmvd, at 15% O_2, 3-hour rolling average	Pipeline quality natural gas w/ S content ≤ 1 grain/100 scf	5.0 ppmvd at 15% O_2, 1-hour rolling average

This information was based on a search of the BACT Clearinghouse database and the latest information available is that for a permit issued to El Colton, in January 2003. This unit is an LM6000 Sprint PC model operating on a simple cycle similar to the five CTGs being proposed by SVEP. The unit was permitted at the above emission levels and has been in operation continuously for over one year. Therefore, emission levels in Table 15 are now officially considered BACT for a simple cycle CTG. The applicant has provided a performance warranty which accompanied the initial application package which indicates that each LMS100 operating on a simple cycle can comply with, and for NOx, even exceed the above BACT requirements. The warranty was provided by GE and is included in the engineering file. The applicant is proposing the BACT levels for this project shown in Table 16 below. However, based on a Facility Permit issued to the City of Riverside (A/N 426694) in April 2005 and another Facility Permit issued to Wellhead Power Colton (A/N 439100) in May 2005, each for a simple cycle LM6000 PC Sprint CTG, the averaging times for NOx, CO, and VOC in those permits were reduced from a 3-hour rolling average to a more restrictive 1-hour rolling average. AQMD now considers the more restrictive 1-hour averaging times to be Achieved in Practice and SVEP will therefore be required to comply with the 1-hour averages for NOx, CO, and VOC.

Table 16 - Proposed BACT for SVEP CTGs

NOx	CO	VOC	PM_{10}/SOx	NH_3
2.5 ppmvd, @ 15% O_2, ~~3~~ 1-hour average	6.0 ppmvd, @ 15% O_2, ~~3~~ 1-hour average	2.0 ppmvd, @ 15% O_2, ~~3~~ 1-hour average	PUC quality natural gas w/ S content ≤ 1 grain/100 scf	5.0 ppmvd @ 15% O_2, 1-hour average

A NOx CEMS will be used to verify compliance with the NOx BACT limit and a CO CEMS will be used to verify compliance with the CO BACT limit. The proposed control levels in the table above will exceed the current BACT requirements for NOx and will meet current BACT requirements for all remaining criteria pollutants including NH_3. BACT is satisfied for each of the CTGs.

RULE 1303(a) and Rule 2005(b)(1)(A)-BACT – Emergency Fire Pump

The emergency fire pump is required to employ BACT because the maximum daily emissions from this source are expected to exceed 1 lb/day. As a starting point, the BACT Guidelines found in Part D – Non Major Polluting Facilities specify the following for emergency internal combustion engines:

EPA Tier III Certification Levels Required for Compression Ignition Engines

Rating/size	Deemed Complete after	NMHC+NOx (gm/BHP-hr)	CO (gm/BHP-hr)	PM_{10} (gm/BHP-hr)
50≤BHP<100	6/30/2008	3.5	3.7	0.30
100≤BHP<175	6/30/2007	3.0	3.7	0.22
175≤BHP<300	7/13/2006	3.0	2.6	0.15
300≤BHP<750	**7/13/2006**	**3.0**	**2.6**	**0.15**

The engine falls into the EPA Tier III BACT category highlighted above. However, since SVEP will be a Major Polluting Facility as defined in AQMDs BACT Guidelines, BACT for Major Sources applies. Four compression ignition emergency fire pump engines were permitted between 12/13/2000 and 12/9/2003, and the permits were issued to LA County (A/N 418342), East LA College (A/N 417691), Ultramar (A/N 395874), and Pharmavite (A/N 372822). Each of these engines drives an emergency fire pump rated between 110 bhp and 300 bhp. A closer search of AQMD's BACT Clearinghouse for each of these engines reveals no significant advancements in BACT determinations for this category of engine. As for PM_{10}, some diesel fired engines are currently employing particulate traps to control PM_{10} emissions. As such, EME will be required to evaluate the technological feasibility of using a particulate trap on the emergency fire pump. In the event that it is not technologically feasible to install a particulate trap to control PM_{10} emissions, the Tier III BACT levels will apply to the emergency fire pump, unless it can be demonstrated, according to AQMD BACT Guidelines, that there are currently no UL listed fire pumps which can meet the Tier III emission standards. In that case, Tier II limits will apply.

EME has submitted a letter dated December 11, 2006 from Clarke, the engine manufacturer, which indicates the installation of after-treatment devices such as particulate traps will compromise reliability and performance and most importantly, <u>safe operation</u> of the fire pump, and that its installation would most likely void the fire pump's UL certification. Therefore, EME proceeded to investigate the possibility of purchasing an engine which will comply with the Tier III emission standards. Currently, according to EME, in a letter dated December 18, 2006 from Clarke, fire pumps which are UL certified that can meet Tier III standards are currently not being provided or sold and are still in development. Therefore, the Tier II standards apply to this fire pump. BACT for SOx emissions for compression ignition emergency fire pumps is diesel fuel with a sulfur content no greater than 0.0015% by weight. A BACT summary for the emergency fire pump is shown below.

Proposed BACT for Emergency Fire Pump (A/N 450943)

Pollutant	EPA Tier II Levels	Proposed BACT	Comply (Yes/No)
NOx+NMHC	4.8 gm/BHP-hr	4.65 gm/BHP-hr	Yes
CO	2.6 gm/BHP-hr	0.45 gm/BHP-hr	Yes
PM_{10}	0.15 gm/BHP-hr	0.09 gm/BHP-hr or particulate trap	Yes (Will meet emission limit in lieu of particulate trap)
SOx	On or after June 1, 2004 the user may only purchase diesel fuel with a sulfur content no greater than 0.0015% by weight (Rule 431.2)		Yes

The manufacturer has indicated that this engine can comply with the Tier II emission levels specified above, and the user will only purchase diesel fuel with a sulfur content of no greater than 0.0015% by weight. The emergency fire pump is expected to comply with current BACT.

RULE 1303(a)-BACT – Cooling Tower
Rule 219(e)(3) provides and exemption for water cooling towers and water cooling ponds not used for evaporative cooling of process water or not used for evaporative cooling of water from barometric jets or from barometric condensers and in which no chromium compounds are contained. The 5-cell cooling tower being proposed at SVEP will meet the requirements of Rule 219(e)(3) and is therefore exempt from NSR. BACT therefore does not apply.

RULE 1303(a)-BACT – Ammonia Storage Tank
A pressure relief valve that will be set at no less than 25 psig will control ammonia emissions from the storage tank. In addition, a vapor return line will be used to control ammonia emissions during storage tank filling operations. Based on the above, compliance with BACT requirements is expected.

Based on the above BACT analysis, the 5 CTGs, the emergency fire pump, and the ammonia tank will comply with the current BACT requirements found in Regulation XIII (for the non-RECLAIM pollutants) and in Regulation XX (for the RECLAIM pollutants). BACT for all equipment is satisfied.

RULE 1303(b)(1) and Rule 2005(b)(1)(B) - Modeling
The applicant has conducted air dispersion modeling using the EPA Industrial Source Complex Short Term ISCST3 air dispersion model, Version 3. The Tier 4 Health Risk Assessment was conducted in accordance with guidelines set forth by the California Office of Environmental Health Hazard Assessment (OEHHA) and the California Air Resources Board (CARB). The OEHHA/CARB computer program (HARP) was used to determine the health risk assessment. The air dispersion model was run at a single normalized emission rate of 1.0 gram/sec. The applicant has submitted modeling results for both a commissioning and non-commissioning year which considered building downwash effects through the use of the EPA Building Profile Input Program, a program which is compatible with the ISCST3 model. Effects of terrain slope, aspect ratio, plume height, wind speed, wind direction and temperature were also accounted for in the analysis. The data was collected at the AQMD's Riverside monitoring station. The analysis further accounted for flat, simple, intermediate, and complex terrain. Terrain features were taken from 1-second U.S. Geological Survey (USGS) data taken from its Digital Elevation Model (DEM). The DEM data provides terrain elevations with 1-meter vertical resolution and 10-meters horizontal resolution based on a UTM coordinate system. The EPA SCREEN3 model was used to estimate potential impacts due to fumigation. Potential fumigation impacts were estimated for NO_2, CO, and SO_2. Table A-2 shown below is found in Rule 1303 and lists the most stringent ambient air quality standards and allowable change in concentration for each air contaminant. The appropriate averaging times are also listed.

Table A-2
Most Stringent Ambient Air Quality Standard and Allowable Change in Concentration
For Each Air Contaminant/Averaging Time Combination

Air Contaminant	Averaging Time	Most Stringent Air Quality Standard		Significant Change in Air Quality Concentration	
Nitrogen Dioxide	1-hour	25 pphm	500 μg/m^3	1 pphm	20 μg/m^3
	Annual	5.3 pphm	100 μg/m^3	0.05 pphm	1 μg/m^3
Carbon Monoxide	1-hour	20 ppm	23 μg/m^3	1 pphm	1.1 μg/m^3
	8-hour	9.0 ppm	10 μg/m^3	0.45 pphm	0.50 μg/m^3
Suspended Particulate Matter <10μm (PM_{10})	24-hour		50 μg/m^3		2.5 μg/m^3
	AGM[10]		30 μg/m^3		1 μg/m^3
Sulfate	24-hour		25 μg/m^3		1 μg/m^3

[10] AGM is the acronym for Annual Geometric Mean

The applicant is required under Rule 1303(b)(1) to demonstrate compliance with one of the following requirements:

(a) The most stringent air quality standard shown in Table A-2 above, or
(b) The significant change in air quality concentration standards shown in Table A-2 above, if the most stringent air quality standards are exceeded

The applicant has provided the following modeled maximum project impacts for each individual turbine at SVEP. Therefore, the numbers in the table below are on a permit unit basis. Each individual turbine plus the background concentration is less than the most stringent standard.

Maximum Project Impacts for SVEP for Attainment Pollutants

	Average	CTG No.1 (μg/m³)	CTG No.2 (μg/m³)	CTG No.3 (μg/m³)	CTG No.4 (μg/m³)	CTG No.5 (μg/m³)	Bkgrnd (μg/m³)	Most Stringent Standard (μg/m³)	Comply (Yes/No)
NOx	1-hr	7.60	7.60	7.50	7.50	7.40	191.3	470	Yes
	Annual	0.18	0.18	0.18	0.18	0.18	45.9	100	Yes
SO_2	1-hr	0.80	0.80	0.70	0.70	0.60	53.2	650	Yes
	3-hr	0.80	0.80	0.70	0.70	0.60	53.2	1,300	Yes
	24-hr	0.30	0.30	0.30	0.20	0.20	39.9	109	Yes
	Annual	0.016	0.016	0.016	0.016	0.016	8	80	Yes
CO	1-hr	11.1	11.1	11.1	11.0	11.0	8,153.1	23,000	Yes
	8-hr	12.8	12.8	12.7	12.7	12.6	4,542.4	10,000	Yes

Since PM_{10} is a non-attainment pollutant, it is required to comply with the 24-hour and annual PM_{10} significance levels in the table below. This table shows the 24-hour and the annual significance levels for turbines 1 through 5.

Significance Modeling for SVEP for Non-Attainment Pollutants, (μg/m³)

Equipment	24-hour PM_{10} Concentration	24 hour PM_{10} Significance Level	Annual PM_{10} Concentration	Annual PM_{10} Significance Level	Comply (Yes/No)
Turbine No. 1	2.245	2.5	0.156	1	Yes
Turbine No. 2	2.192	2.5	0.160	1	Yes
Turbine No. 3	2.143	2.5	0.162	1	Yes
Turbine No. 4	2.095	2.5	0.164	1	Yes
Turbine No. 5	2.049	2.5	0.166	1	Yes

AQMD modeling staff reviewed the applicant's analyses for both air quality modeling and health risk assessment (HRA). Modeling staff provided their comments in a memorandum from Ms. Jill Whynot to Mr. Mike Mills dated November 30, 2006. A copy of this memorandum is contained in the engineering file. Staff's review of the modeling and HRA analyses concluded that the applicant used EPA ISCST3 model version 02035 along with the appropriate model options in the analyses for NOx, CO, PM_{10}, and SO_2. The applicant modeled both the cumulative and individual permit unit impacts for the project. The memorandum states that the ISCST3 modeling as performed by the applicant conforms to the District's dispersion modeling requirements. No significant deficiencies were reported.

RULE 1303(b)(2) and Rule 2005(b)(2)-Offsets – LMS100 PA CTGs

Since SVEP is a new facility with an emissions increase, offsets will be required for all criteria pollutants. SVEP will be included in NOx RECLAIM and as such, NOx increases will be offset with RTCs at a 1.0 to1 ratio. Non-RECLAIM criteria pollutants (CO, VOC, SOx, and PM_{10}) will be offset by either the purchase of Emission Reduction Credits (ERCs) and/or Priority Reserve Credits (PRCs) at a 1.2 to 1 ratio. The facility may elect to offset emission increases using either purchased ERCs or PRCs or any combination thereof as allowed by AQMD Rules and Regulations. The required RTCs for NOx for the first and second years of operation are shown below. The values include start-ups, commissioning (first year only), normal operation, and shutdowns. (The total emissions for the second year excludes commissioning).

Required NOx RTCs

Operating Condition 100	Hours per Year	NOx (lb/hr)	NOx (lb/year) per device	NOx (lb/year) cumulative
CTGs				
Startup	350	10.42	3,647.00	18,235.00
Shutdown	350	11.00	3,850.00	19,250.00
Normal Operation	2,634	8.21	21,625.14	108,125.70
Commissioning	134	71.21	9,542.14	47,710.70
CTG Totals	3,468		38,664.28	193,321.40
Emergency Fire Pump	199	10.54	2,097.46	2,097.46
Total 1st Year Emissions (lb/year)			40,761.74	195,418.86
Offset Ratio			1.00	1.00
1st year RTCs (lb/year)			40,761.74	195,418.86
2nd year RTCs (lb/year)			**32,319.74**	**153,208.86**

Table 17 shows the facility-wide 30-day averages for CO, VOC, PM_{10} and SOx for informational purposes only. Offsets are based upon 30-day averages from individual permit units. As mentioned above, SVEP may elect to use both ERCs and PRCs to provide the required offsets, as shown below, however, PRCs are only available for CO, PM_{10} and SOx as depicted in the table below. ERCs will be purchased for the VOC offsets. The amounts in Table 18 are required to fully offset the facility increases and satisfy the requirements of Rule 1303(b)(2): Note maximum 30-day average for PM_{10} excludes the emissions from the cooling tower per Rule 219(e)(3).

Table 17 – 30-Day Averages for the Entire Facility, (lb/day)

	NOx	CO	VOC	SOx	PM_{10}
Maximum 30 Day Average		1,240	151	46	463

Table 18 - Required Offsets for Non-RECLAIM Pollutants (per-turbine basis, lb/day)

	NOx	CO	VOC	SOx	PM_{10}
Maximum 30 Day Average		248	30	9	93
ERC Offset Ratio		1.2	1.2	1.2	1.2
PRC Offset Ratio		1.2	N/A	1.2	1.2
Required Offsets if ERCs are chosen		**298**	**36**	**11**	**112**
Required Offsets if PRCs are chosen		**298**	**N/A**	**11**	**112**

The facility's maximum monthly and annual fuel usage for the simultaneous operation of the 5 CTGs will be 1,966 mmscf and 14,725 mmscf, respectively, based on operating condition 100. The monthly fuel cap will correspond to 463 hours/month of operation. This value was selected by SVEP. The monthly and annual fuel usage for the emergency fire pump are 264 gallons and 3,200 gallons, respectively. The calculations are shown below and a monthly fuel cap will be included on the Facility Permit as a condition.

```
Monthly:
CTGFuel= (803.3 MMBTU/hr)(1.11)(1 scf/1,050 BTU)(463 hr/month)(5 CTGs) = 1,966 MMscf/month
ICEFuel= (16.0 gal/hr)*16.5 hr/month = 264 gal/month

Annually:
CTGFuel= (803.3 MMBTU/hr)(1.11)(1 scf/1,050 BTU)(3,468 hr/year)(5 CTGs) = 14,725 MMscf/year
ICEFuel= (16.0 gal/hr)*199.99 hr/year = 3,200 gal/year
```

Table 19 below shows the total amount of ERC's that EME has purchased as of January 19, 2007. The table consists of several ERC certificates for VOC as shown. Shaded areas in the table indicate that no ERC's for that particular pollutant have been acquired by EME as of January 19, 2007.

Table 19 – Total Amount of Emission Reduction Credits currently held by EME, Sun Valley Energy, LLC

Pollutant	ERC Certificate No.	Date of Purchase	Origin	Seller	Amount of ERC (lb/day)
VOC	AQ003679	10/23/2006	Electrofilm Manufacturing	Electrofilm Manufacturing	8
VOC	AQ002683	11/8/2006	Magnatek, Inc	Magnetek, Inc	1
VOC	AQ006303	11/13/2006	Scope Products	Greg K Environmental Fund	100
VOC	AQ004209	11/13/2006	Plastic Dress Up Co	Dart Container Corp	117
CO					
PM_{10}					
SOx					

SVEP has indicated that the required amounts of offsets will be provided prior to issuance of the Facility Permit. Compliance with offset requirements of Rules 1303(b)(2) and 2005(b)(2) is expected.

RULES 1303(b)(3)-Sensitive Zone Requirements and 2005(e)-Trading Zone Restrictions

Both rules state that credits must be obtained from the appropriate trading zone. In the case of Rule 1303(b)(3), unless credits are obtained from the Priority Reserve, facilities located in the South Coast Air Basin are subject to the Sensitive Zone requirements specified in Health & Safety Code Section 40410.5. SVEP is located in Zone 2a and is therefore eligible to obtain its ERCs from either Zone 1 or Zone 2a. Similarly in the case of Rule 2005(e), SVEP, because of its location may obtain RTCs from either Zone 1 or Zone 2, at its choosing. Compliance is expected with both rules.

RULE 1303(b)(4)-Facility Compliance
The new facility will comply with all applicable Rules and Regulations of the AQMD.

RULE 1303(b)(5)-Major Polluting Facility
SVEP has addressed the alternative analysis, statewide compliance, plume visibility, and CEQA requirements of this rule and based on experience with similar equipment recently permitted, it is expected that SVEP will comply with the provisions of this rule.

Rule 1303(b)(5)(A) – Alternative Analysis
The applicant is required to conduct an analysis of alternative sites, sizes, production processes, and environmental control techniques for the SVEP and to demonstrate that the benefits of the proposed project outweigh the environmental and social costs associated with this project.

EME has performed a comparative evaluation of alternative sites as part of the AFC process and has concluded that the benefits of providing additional electricity and increased employment in the surrounding area will outweigh the environmental and social costs incurred in the construction and operation of the proposed facility.

Rule 1303(b)(5)(B) – Statewide Compliance
EME has certified in the 400-A form that all major sources under its ownership or control in the State of California are in compliance with all federal, state, and local air quality rules and regulations. In addition, EME has submitted an email to the AQMD dated October 19, 2006 stating that "any and all facilities that EME owns or operates in the State of California (including the proposed SVEP) are in compliance or are on a schedule for compliance with all applicable emission limitations and standards under the Clean Air Act". Therefore, compliance is expected.

Rule 1303(b)(5)(C) – Protection of Visibility
Modeling is required if the source is within a Class I area and the NOx and PM_{10} emissions exceed 40 TPY and 15 TYP respectively. Since the nearest Class I area is located well beyond the proposed SVEP site, modeling from plume visibility is not required, however, the applicant has provided modeling impact data for the Class I areas as part of the AFC process. Compliance is expected.

Rule 1303(b)(5)(D) – Compliance through CEQA
The California Energy Commission's (CEC) certification process is essentially equivalent to CEQA. Since the applicant is required to receive a certification from the CEC, the applicable CEQA requirements and deficiencies will be addressed. Compliance is expected.

RULE 1309.1-Priority Reserve
This rule requires an electrical generating facility (EGF) to comply with the requirements in R-1309(c): As part of the recent amendments to Rule 1309.1-Priority Reserve, (September 8, 2006), the AQMD Executive Officer committed to hold a public meeting for each project prior to accessing the Priority Reserve. AQMD held a public meeting to inform the public about the specifics of the proposed project. The meeting was held on October 18, 2006. Topics discussed included facility emissions, local impacts on schools, surrounding area, and cumulative impacts of Inland Empire Energy Center and the proposed Sun Valley Energy Project. The requirements and compliance status are summarized in Table 20 below:

Table 20 - Rule 1309.1 Requirements and Compliance Determination

REQUIREMENTS	COMPLIANCE (Yes/No)
Rule 1309.1(c)(1) - Permit condition requiring facility to comply with BARCT for pollutants received from Priority Reserve for all existing sources prior to operation of any new sources	**(YES)** Since there are no existing sources at this facility, BARCT is not applicable and the new equipment will be constructed using BACT for simple cycle power plants. These emission limits are the lowest levels achieved in practice under federal LAER. Compliance is expected
Rule 1309.1(c)(2) - The applicant must pay a mitigation fee pursuant to subdivision (g)	**(YES)** The applicant will pay this fee for each pollutant upon securing PRCs.
Rule 1309.1(c)(3) - Conducts due diligence effort approved by the Executive Officer to secure ERCs for requested Priority Reserve pollutants	**(CONTINUOUS)** The applicant has submitted written correspondence to AQMD (see letter in file dated September 27, 2006 from Latham & Watkins to Mr. Mohsen Nazemi) which indicates the applicant is in the process of attempting to secure ERCs for the requested Priority Reserve pollutants. AQMD has received a letter dated September 27, 2006 which provided information regarding the progess in securing offsets for SVEP. EME secured additional VOC ERCs on October 23, November 8, and November 13, 2006 for a total of 226 lb/day. No additional ERCs have been purchased as of January 19, 2007. EME will continue to provide progress reports when additional ERCs are secured.
Rule 1309.1(c)(4) - Applicant has the new source fully and legally operational at rated capacity within 3 years following AQMD permit to Construct issuance or CEC certification, whichever is later	**(YES)** The applicant is scheduled to have the new facility fully operational at its rated capacity by July 2008.
Rule 1309.1(c)(5) - Applicant must enter into a long-term contract with the State of California to sell at least 50% of the portion of power which it has generated using PRCs	**(YES)** The applicant is a power generator and is engaged in the sale of generated power to end users. Most of the power will be supplied to the state's electrical grid. However, at this time, it is the AQMD's understanding that the State of California is not offering long term contracts for the acquisition of power.
Rule 1309.1(c)(6) - Applicant for an in-Basin EGF must purchase PRCs at an offset ratio of 1.2 -to-1.0	**(YES)** The applicant has proposed to purchase both ERCs and PRC at an offset ratio of 1.2-to-1.0.
Rule 1309.1(c)(7) - Applicant for a Downwind Air Basin EGF shall obtain credits at an offset ratio as determined by the downwind air district	**(NOT APPLICABLE)** This facility is located within the South Coast Air Basin (SCAB) and the applicable offset ratio for PRCs in the SCAB is 1.2-to-1.0.
Rule 1309.1(c)(8) - Applicant for Permit to Construct must agree to a permit condition which requires new sources to be fully and legally operational at rated capacity within 3 years. An applicant that is a municipality must have an additional year if the EGF contains a renewable energy component with a rated capacity of at least 50 MW of renewable energy.	**(YES)** The applicant is scheduled to have the new facility fully operational at its rated capacity by July 2008.
BASED ON THE INFORMATION IN THIS TABLE, SVEP CAN COMPLY WITH THE APPLICABLE REQUIREMETS OF RULE 1309.1	

Rule 1401 – New Source Review of Toxic Air Contaminants

This rule specifies limits for maximum individual cancer risk (MICR), acute hazard index (HIA), chronic hazard index (HIC) and cancer burden (CB) from new permit units, relocations, or modifications to existing permits which emit toxic air contaminants. Rule 1401 requirements are summarized as follows:

Table 21 – Rule 1401 Requirements

Parameters and Specifications	Rule 1401 Requirements
MICR, without T-BACT	$\leq 1 \times 10^{-6}$
MICR, with T-BACT	$\leq 1 \times 10^{-5}$
Acute Hazard Index	$\leq$ 1.0
Chronic Hazard Index	$\leq$ 1.0
Cancer Burden	$\leq$ 0.5

The applicant performed a Tier 4 health risk assessment using the Hot Spots Analysis and Reporting Program (HARP, version 1.2a). The analysis included an estimate of the MICR for the nearest residential and commercial receptors, the acute and chronic hazard indices for the entire facility. PRA modeling staff reviewed the applicant's methodology and procedures used, and re-ran the HARP model and verified the health risk and hazard indices which were presented by the applicant. It was noted that a 15 percent fractional consumption rate for home grown produce for residential receptors was used in determining the risk. The AQMD's HRA procedures require the use of a 5.2 percent fractional consumption rate. It was further noted that the cancer risk for the commercial receptor was estimated by applying an adjustment factor to the residential cancer risk, when the "point estimate" risk calculation method should be used. The HARP model was re-run with the corrected fractional consumption rate and point estimate methodology. PRA staff determined that each of the health risk values for MICR, HIA and HIC were appropriately estimated (see memorandum in file, dated November 30, 2006 from Ms. Jill Whynot to Mr. Mike Mills, and subsequent email in file from Yi Huang to Ken Coats dated December 7, 2006). Table 22 below is a summary of the revised cancer and non-cancer risk assessment results, which include the cumulative risks from the cooling tower and the turbines, using the corrected fractional consumption rates and point source methodology. The cancer burden is not calculated because the MICR is less than 1×10^{-6} for both residential and commercial receptors.

Table 22 – Rule 1401 Modeled Results

Risk Parameter	Residential	Commercial	Rule 1401 Requirements	Compliance (Yes/No)
MICR	4.51×10^{-9}	2.22×10^{-10}	$\leq 1 \times 10^{-6}$	Yes
HIA	0.0028	0.00616	$\leq$ 1.0	Yes
HIC	0.0000877	0.0000243	$\leq$ 1.0	Yes

Table 22 shows that SVEP will comply with the applicable requirements of Rule 1401. The cancer burden is not computed because the highest MICR (in this case, the commercial MICR) is less than 1×10^{-6}.

RULE 1470-Requirements for Stationary Diesel-Fueled Internal Combustion and Other Compression Ignition Engines.

Rule 1470 imposes the following requirements on compression ignition engines:

Paragraph (c)(1) requires the use of CARB Diesel fuel. The use of No. 2 diesel fuel will satisfy this requirement. Paragraph (c)(2)(A) imposes operating requirements for engines located within 500 feet from a school. Since the engine is located greater than 500 feet to the nearest school, the requirements of this section are not applicable.

Paragraph (c)(2)(B) allows operation of this device during an impending rotating electric power outage only if:

1. The permit specifically allows this operation
2. The utility company has actually ordered the outage
3. The engine is in a specific location covered by the outage.
4. The engine is operated no more than 30 minutes prior to the outage, and
5. The engine operation is terminated immediately after the outage.

AQMD will require a condition to limit the maintenance and testing to less than 50 hours per year. This engine is expected to meet these requirements.

Paragraph (c)(2)(C) limits hours for maintenance and testing to 50 hours per year for PM_{10} emissions up to 0.15 gm/bhp-hr, and a maximum of 100 hours per year for PM_{10} emissions up to 0.01 gm/bhp-hr. Therefore, the engine will comply with paragraph (c)(2)(C). Also, part (iv) of paragraph (c)(2)(C) requires that the engine meet the standards for off road engines in Title 13, CCR section 2423. This engine will comply with the requirements for off road engines. Therefore, compliance with Rule 1470 is expected.

Rule 2005(g) – Additional Requirements
As with Rule 1303(b)(5) for the Non-RECLAIM pollutants, SVEP has addressed the alternative analysis, statewide compliance, plume visibility, and CEQA requirements of this rule for NOx and SOx and based on experience with similar equipment recently permitted, it is expected that SVEP will comply with the provisions of this rule.

Rule 2005(g) – Additional Requirements
As with Rule 1303(b)(5) for the Non-RECLAIM pollutants, SVEP has addressed the alternative analysis, statewide compliance, protection of visibility, and CEQA compliance requirements of this rule for NOx. These requirements are essentially the same as those found in Rule 1303(b)(5), subparts A through D for non-RECLAIM pollutants, and are summarized below.

Rule 2005(g)(1) – Statewide Compliance
EME has certified in the 400-A form that all major sources under its ownership or control in the State of California are in compliance with all federal, state, and local air quality rules and regulations. In addition, EME has submitted an email to the AQMD dated October 19, 2006 stating that "any and all facilities that EME owns or operates in the State of California (including the proposed SVEP) are in compliance or are on a schedule for compliance with all applicable emission limitations and standards under the Clean Air Act. Therefore, compliance is expected.

Rule 2005(g)(2) – Alternative Analysis
The applicant is required to conduct an analysis of alternative sites, sizes, production processes, environmental control techniques for the SVEP and to demonstrate that the benefits of the proposed project outweigh the environmental and social costs associated with this project. EME has performed a comparative evaluation of alternative sites as part of the AFC process and has concluded that the benefits of providing additional electricity and increased employment in the surrounding area will outweigh the environmental and social costs incurred in the construction and operation of the proposed facility.

Rule 2005(g)(3) – Compliance through CEQA
The California Energy Commission's (CEC) certification process is a CEQA certified process. Since the applicant is required to receive a certification from the CEC, the applicable CEQA requirements and deficiencies will be addressed. Compliance is expected

Rule 2005(g)(4) – Protection of Visibility
Modeling is required if the source is within a Class I area and the NOx emissions exceed 40 TPY. Since the nearest Class I area is located well beyond the proposed SVEP site, modeling from plume visibility is not required, however, the applicant has provided modeling impact data for the Class I areas as part of the AFC process. Compliance is expected

Rule 2005(h) – Public Notice
SVEP will comply with the requirements for Public Notice found in Rule 212. Therefore compliance with Rule 2005(h) is demonstrated.

Rule 2005(i) – Rule 1401 Compliance.
SVEP will comply with Rule 1401 as demonstrated in the Tier 4 analysis and subsequently reviewed and found to be satisfactory by AQMD modeling staff. Compliance is expected.

Rule 2005(j) – Compliance with State and Federal NSR.
SVEP will comply with the provisions of this rule by having demonstrated compliance with AQMD NSR Regulations XIII and Rule 2005-NSR for RECLAIM.

REGULATION XVII-Prevention of Significant Deterioration
The District Governing Board in its action on February 7, 2003, authorized the Executive Officer, upon withdrawal of the EPA PSD delegation, not to request any further delegation and to allow the EPA to terminate the AQMD's PSD delegation agreement and for EPA to become the permitting agency for PSD sources in the AQMD. The Board determined that Regulation XVII is inactive upon EPA's withdrawal of delegation and shall remain inactive unless and until the EPA provides the AQMD with new delegation of authority to act either in full or on a Facility/Permit-Specific basis. The delegation was rescinded on March 3, 2003 by EPA.

The District Governing Board in its April 1, 2005 meeting reaffirmed its previous action on February 7, 2003 to relinquish PSD analysis back to federal government and render Regulation XVII inactive unless the District receives new delegation in part or in full from the EPA.

Based on the Governing Board's actions, this rule is ineffective and no analysis is required for any pollutant subject to federal PSD requirement. The AQMD has sent the applicant a notification to contact the EPA directly for applicability of PSD to the proposed project. AQMD sent a letter to the applicant on December 8, 2005 and instructed the applicant to contact EPA directly regarding implementation of PSD.

INTERIM PERIOD EMISSION FACTORS
RECLAIM requires that a NOx emission factor be used for reporting emissions during the interim reporting period. The interim period is defined as a period, typically 12 months in duration, when the CEMS has not been certified. During this period, the emissions cannot be accurately quantified, monitored, or verified. The emissions during this period are assumed to be at uncontrolled levels. The interim reporting period

can be broken down into the two parts which includes the commissioning period in which an uncontrolled[11] emission rate is assumed, and the remaining period at which controlled rates at BACT are assumed.

Since SVEP will be included in NOx RECLAIM, an interim period emission factor for NOx will be determined. Although not a RECLAIM pollutant, a CO emission factor will also be calculated so that the applicant may use it to report emissions during the interim period when the CEMS is not yet certified for CO. In the event CEMS data is not available, NOx, CO, and SOx emissions during the interim period will be calculated using monthly fuel usage and the emission factors derived below. There will be two interim period emission factors calculated for NOx and two interim period emission factors calculated for CO. The first factor will be for use during commissioning stage when the CTGs are assumed to be operating at uncontrolled levels and the second factor will be for use after commissioning is complete and the CTGs are assumed to operate at BACT levels. The specific calculations are shown in Appendix G and the results are shown in the tables below.

Commissioning Period

Pollutants	NOx	CO
Total emissions (lbs)	47,710	48,640
Total Fuel (mmscf)	386.43	386.43
Emission Factor (lb/mmscf)	**123.46**	**125.87**

Remaining Period (Non-Commissioning)

Pollutants	NOx	CO
Total emissions (lbs)	153,736	261,280
Total Fuel (mmscf)	14,156.7	14,156.7
Emission Factor (lb/mmscf)	**10.86**	**18.46**

CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA)

The CEC is the lead agency for this project and EME filed an Application for Certification (05-AFC-3) for the project on December 1, 2005. SVEP will be subject to the CEC's 12-month energy facility licensing process which will address public issues and concerns involving zoning, biological resources, water resources, air quality, transmission, public health and safety, and their resolution. The CEC's 12-month licensing process is a certified regulatory program under CEQA and includes several opportunities for public participation. The CEC's license/certification subsumes all requirements of state, local, or regional agencies otherwise required before a new plant is constructed. The CEC coordinates its review of the facility with the federal, state, and local agencies that will be issuing permits to ensure that its certification incorporates the conditions that would be required by these various agencies. The AFC process is the functional equivalent of a traditional CEQA review and will address and resolve issues related to CEQA.

40CFR Part 60 Subpart GG – NSPPS for Stationary Gas Turbines

The CTGs proposed for construction at Sun Valley are subject to the requirements of 40CFR60 Subpart KKKK, and are exempt from 40CFR60 Subpart GG per 40 CFR60 Subpart KKKK, §60.4305 (b).

[11] The emission factor for the commissioning period is an average for the entire 134 hour commissioning period. During this period, the turbines may be uncontrolled, partially controlled, or 100% controlled.

40CFR Part 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines
Subpart KKKK establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines with a heat input greater than 10 MMBTU/hr (10.7 gigajoules per hour), based on higher heating value, which commenced construction, modification or reconstruction after February 18, 2005.

§60.4320(a) The turbine is natural gas-fired and has a heat input > 850 MMBTU/hr, therefore, it is subject to a NO_X emission limit of 15 ppmv @ 15% O_2 from Table 1 of this subpart. The turbine is required to comply with BACT for NOx which is officially at 3.5 ppmv at 15% O2, dry basis for a simple cycle plant. However, GE has submitted performance warranties which indicate the CTGs will meet a NOx level of 2.5 ppmv at 15% O2 on a 1-hour average which is more stringent than this subpart. Therefore, compliance with this section is expected.

§60.4330(a)(2) Natural gas fuel burned in the turbine has a sulfur content of 0.0006 lb-SO_2/MMBtu, which is less than 0.06 lb-SO_2/MMBTU (26 ng-SO_2/J) required by this section. Therefore, compliance with the sulfur dioxide limits of this section is expected.

§60.4335 The LMS100PA turbines use water injection to help reduce NO_X to compliance levels. Monitoring is required and will be accomplished with a CEMS; therefore, compliance with this section is expected with a certified CEMS.

§60.4345 The CEMS is required to be certified according to the Performance Specification 2 (PS 2) in appendix B to this part. SCE will be required to file a CEMS application package with Source Test Engineering to certify the CEMS to meet the requirements of Rule 218 or 40CFR60 appendix B. Therefore, compliance with this section is expected.

§60.4400(a) An initial source test will be required per §60.8. The annual source testing requirement for NOx will be satisfied through the annual RATAs performed on the CEMS. Compliance with the source testing requirements is expected.

40CFR Part 72 – Acid Rain Provisions
SVEP is subject to the requirements of the federal Acid Rain program because the electricity generated will be rated at greater than 25 MW. This program is similar to RECLAIM in that facilities are required to cover SO_2 emissions with SO_2 allowances that are similar in concept to RTC's. SO_2 allowances are however, not required in any year when the unit emits less than 1,000 lbs of SO_2. Facilities with insufficient allowances are required to purchase SO_2 credits on the open market. In addition, both NOx and SO_2 emissions will be monitored and reported directly to USEPA. Based on the above, compliance with this rule is expected.

REGULATION XXX – Title V
SVEP is a Title V facility because the cumulative emissions will exceed the Title V major source thresholds and because it is also subject to the federal acid rain provisions. The initial Title V permit will be processed and the required public notice will be sent along with the Rule 212(g) Public Notice, which is also required for this project. EPA is afforded the opportunity to review and comment on the project within a 45-day review period.

COMMENTS / RESPONSES:

As mentioned above in the Rule 1309.1 analysis, part of the recent amendments to Rule 1309.1-Priority Reserve, (September 8, 2006), the AQMD Executive Officer committed to hold a public meeting for each project prior to accessing the Priority Reserve. AQMD held a public meeting to inform the public about the specifics of the proposed project. The meeting was held on October 18, 2006. Topics discussed included facility emissions, local impacts on schools, and surrounding area. At this meeting, several audience members spoke in favor of constructing the proposed power plant to provide additional electricity during peak demand hours and to create much needed jobs, and some in opposition of the project expressing concerns about potential public health impacts. Most of the comments received were answered on-site during the meeting. However, one comment in particular expressed concerns about the cumulative emissions and public health impacts between the proposed Sun Valley Energy Project and the Inland Empire Energy Center (IEEC) located nearby. Based on this comment AQMD looked into the combined modeling and health risk impacts from both SVEP and IEEC power plants on the local community.

Combined Modeling Impacts from SVEP and IEEC on Local Community

		New Impacts, μg/m^3 (SVEP)	Existing Impacts, μg/m^3 (IEEC)
PM_{10}	24-hr	11.0	1.22
	Annual	0.80	1.04
NO_2	1-hr	261.40	0
	Annual	1.14	1.67
CO	1-hr	55.15	18.22
	8-hr	64.51	7.06

Combined Health Risk Impacts from SVEP and IEEC on Local Community

	Health Effect	Receptor	Impact
New Impacts (SVEP)	Cancer risk, μg/m^3	Uninhabited Area	0.03EE-6
		Residential	<0.01EE-6
		Commercial	<0.01EE-6
	Acute Hazard Index, (dimensionless)		0.01
	Chronic Hazard Index, (dimensionless)		0.09
Existing Impacts (IEEC)	Health Effect	Receptor	Impact
	Cancer Risk, μg/m^3	Uninhabited Area	2.29EE-6
		Residential	0.53EE-6
		Commercial	0.16EE-6
	Acute Hazard Index, (dimensionless)		0.05
	Chronic Hazard Index, (dimensionless)		0.09

The individual impacts of each project have been evaluated and addressed in the earlier analysis for SVEP and in the application evaluation for the IEEC project and have both shown compliance with requirements of all applicable Rules and Regulations. The results of the combined analysis are shown in the above tables, and summarize the impacts of criteria pollutants and health risks on the local community. This analysis was strictly performed to provide additional information with respect to the comments received at the public meeting.

OVERALL EVALUATION / RECOMMENDATION(S)

Issue a Facility Permit to Construct with the following permit conditions.

PERMIT CONDITIONS

(LMS100PA CTGs)

A63.1 The operator shall limit emission from this equipment as follows:

CONTAMINANT	EMISSION LIMIT
PM_{10}	2,778 LBS IN ANY ONE MONTH
CO	6,532 LBS IN ANY ONE MONTH
SOx	281 LBS IN ANY ONE MONTH
VOC	887 LBS IN ANY ONE MONTH

The operator shall calculate the monthly emissions for VOC, PM10 and SOx using the equation below and the following emission factors: VOC: 2.00 lb/mmcf; PM10: 6.93 lb/mmcf; and SOx: 0.71 lb/mmcf.

Monthly Emissions, lb/mon = X (E.F.)

Where X = monthly fuel usage, mmscf/month and E.F. = emission factor indicated above.

Compliance with the CO emission limit shall be verified through valid CEMS data.

The operator shall calculate the emission limit(s) for the purpose of determining compliance with the monthly CO limit in the absence of valid CEMS data by using the above equation and the following emission factor(s):

(A) During the commissioning period and prior to CO catalyst installation - 125.87 lbs CO/mmcf

(B) After installation of the CO catalyst but prior to CO CEMS certification testing - 18.46 lb CO/mmcf. The emission rate shall be recalculated in accordance with Condition D82.1 if the approved CEMS certification test resulted in emission concentration higher than 6 ppmv.

(C) After CO CEMS certification testing - 18.46 lb CO/mmcf. After CO CEMS certification test is approved by the AQMD, the emissions monitored by the CEMS and calculated in accordance with condition D82.1 shall be used to calculate emissions.

For the purposes of this condition, the limit(s) shall be based on the emissions from a single turbine. During commissioning, the CO emissions shall not exceed 7,441 lbs in any one month. During commissioning, the VOC emissions shall not exceed 904 lbs in any one month.

The operator shall provide the AQMD with written notification of the date of initial CO catalyst use within seven (7) days of this event.
[Rule 1303 - Offsets]

A99.1 The 2.5 PPM NOx emission limits shall not apply during turbine commissioning, start-up, and shutdown periods. The commissioning period shall not exceed 134 hours. Start-up time shall not exceed 60 minutes for each start-up. Shutdown periods shall not exceed 10 minutes for each shutdown. The turbine shall be limited to a maximum of 350 start-ups per year. Written records of commissioning, start-ups and shutdowns shall be maintained and made available upon request from the Executive Officer.
[Rule 2005]

A99.2 The 6.0 PPM CO emission limits shall not apply during turbine commissioning, start-up, and shutdown periods. The commissioning period shall not exceed 134 hours. Start-up time shall not exceed 60 minutes for each start-up. Shutdown periods shall not exceed 10 minutes for each shutdown. The turbine shall be limited to a maximum of 350 start-ups per year. Written records of commissioning, start-ups and shutdowns shall be maintained and made available upon request from the Executive Officer.
[Rule 1303(a) - BACT, Rule 1303(b)(1) - Modeling, Rule 1303(b)(2) - Offsets]

A99.3 The 123.46 LBS/MMCF NOx emission limit shall only apply during the interim reporting period during initial turbine commissioning to report RECLAIM emissions. The interim reporting period shall not exceed 12 months from entry into RECLAIM.
[Rule 2012 - Requirements for Monitoring, Reporting and Recordkeeping for Oxides of Nitrogen Emissions]

A99.4 The 10.86 LBS/MMCF NOx emission limits shall only apply during the interim reporting period after initial turbine commissioning to report RECLAIM emissions. The interim reporting period shall not exceed 12 months from entry into RECLAIM.
[Rule 2012 - Requirements for Monitoring, Reporting and Recordkeeping for Oxides of Nitrogen Emissions]

A195.1 The 2.5 PPMV NOX emission limit(s) is averaged over 60 minutes at 15 percent O2, dry.
[Rule 2005]

A195.2 The 6.0 PPMV CO emission limit(s) is averaged over 60 minutes at 15 percent O2, dry.
[Rule 1303(a) - BACT, Rule 1303(b)(1) - Modeling, Rule 1303(b)(2) - Offsets]

A195.3 The 2.0 ppmv VOC emission limit(s) is averaged over 60 minutes at 15 percent O2, dry.
[Rule 1303(a) - BACT, Rule 1303(b)(1) - Modeling, Rule 1303(b)(2) - Offsets]

A327.1 For the purpose of determining compliance with District Rule 475, combustion contaminants emissions may exceed the concentration limit or the mass emission limit listed, but not both limits at the same time.
[Rule 475]

C1.1 The operator shall limit the fuel usage to no more than 393 mmcf in any one calendar month.

For the purpose of this condition, fuel usage shall be defined as the total natural gas usage of a single turbine.

The operator shall maintain records in a manner approved by the District to demonstrate compliance with this condition.
[Rule 1303(b)(2) - Offset]

D12.1 The operator shall install and maintain a(n) flow meter to accurately indicate the fuel usage being supplied to the turbine.

The operator shall also install and maintain a device to continuously record the parameter being measured
[Rule 1303(b)(2) - Offset, Rule 2012]

D29.1 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant to be tested	Required Test Method(s)	Averaging Time	Test Location
NOX emissions	District Method 100.1	1 hour	Outlet of the SCR
CO emissions	District Method 100.1	1 hour	Outlet of the SCR
SOX emissions	Approved District method	District approved averaging time	Fuel Sample
VOC emissions	Approved District method	1 hour	Outlet of the SCR
PM10 emissions	Approved District method	District approved averaging time	Outlet of the SCR
NH3 emissions	District method 207.1 and 5.3 or EPA method 17	1 hour	Outlet of the SCR

The test shall be conducted after AQMD approval of the source test protocol, but no later than 180 days after initial start-up. The AQMD shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted to determine the oxygen levels in the exhaust. In addition, the tests shall measure the fuel flow rate (CFH), the flue gas flow rate, and the turbine generating output in MW.

The test shall be conducted in accordance with AQMD approved test protocol. The protocol shall be submitted to the AQMD engineer no later than 45 days before the proposed test date and shall be approved by the AQMD before the test commences. The test protocol shall include the proposed operating conditions of the turbine during the tests, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures.

The test shall be conducted when this equipment is operating at maximum, average, and minimum loads.

The test shall be conducted for compliance verification of the BACT VOC 2.0 ppmv limit.

For natural gas fired turbines only, VOC compliance shall be demonstrated as follows: a) Stack gas samples are extracted into Summa canisters maintaining a final canister pressure between 400-500 mm Hg absolute, b) Pressurization of canisters are done with zero gas analyzed/certified to contain less than 0.05 ppmv total hydrocarbon as carbon, and c) Analysis of canisters are per EPA Method TO-12 (with pre concentration) and temperature of canisters when extracting samples for analysis is not below 70 deg F.

The use of this alternative method for VOC compliance determination does not mean that it is more accurate than AQMD Method 25.3, nor does it mean that it may be used in lieu of AQMD Method 25.3 without prior approval except for the determination of compliance with the VOC BACT level of 2.0 ppmv calculated as carbon for natural gas fired turbines.

Because the VOC BACT level was set using data derived from various source test results, this alternate VOC compliance method provides a fair comparison and represents the best sampling and analysis technique for this purpose at this time. The test results shall be reported with two significant digits.
[Rule 1303(a)(1) - BACT, Rule 1303(b)(2) - Offset, Rule 2005]

D29.2 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant to be tested	Required Test Method(s)	Averaging Time	Test Location
NH3 emissions	District method 207.1 and 5.3 or EPA method 17	1 hour	Outlet of the SCR

The test shall be conducted and the results submitted to the District within 45 days after the test date. The AQMD shall be notified of the date and time of the test at least 7 days prior to the test.

The test shall be conducted at least quarterly during the first twelve months of operation and at least annually thereafter. The NOx concentration, as determined by the CEMS, shall be simultaneously recorded during the ammonia slip test. If the CEMS is inoperable, a test shall be conducted to determine the NOx emissions using District Method 100.1 measured over a 60 minute averaging time period.

The test shall be conducted to demonstrate compliance with the Rule 1303 concentration limit
[Rule 1303(a)(1) - BACT]

D29.3 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant to be tested	Required Test Method(s)	Averaging Time	Test Location
SOX emissions	Approved District method	District approved averaging time	Fuel Sample
VOC emissions	Approved District method	1 hour	Outlet of the SCR
PM10 emissions	Approved District method	District approved averaging time	Outlet of the SCR

The test shall be conducted at least once every three years.
The test shall be conducted to determine the oxygen levels in the exhaust. In addition, the tests shall measure the fuel flow rate (CFH), the flue gas flow rate, and the turbine generating output in MW.

The test shall be conducted in accordance with AQMD approved test protocol. The protocol shall be submitted to the AQMD engineer no later than 45 days before the proposed test date and shall be approved by the AQMD before the test commences. The test protocol shall include the proposed operating conditions of the turbine during the tests, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures.

The test shall be conducted when this equipment is operating at 100 percent load.

The test shall be conducted for compliance verification of the BACT VOC 2.0 ppmv limit.

For natural gas fired turbines only, VOC compliance shall be demonstrated as follows: a) Stack gas samples are extracted into Summa canisters maintaining a final canister pressure between 400-500 mm Hg absolute, b) Pressurization of canisters are done with zero gas analyzed/certified to contain less than 0.05 ppmv total hydrocarbon as carbon, and c) Analysis of canisters are per EPA Method TO-12 (with pre concentration) and temperature of canisters when extracting samples for analysis is not below 70 deg F.

The use of this alternative method for VOC compliance determination does not mean that it is more accurate than AQMD Method 25.3, nor does it mean that it may be used in lieu of AQMD Method 25.3 without prior approval except for the determination of compliance with the VOC BACT level of 2.0 ppmv calculated as carbon for natural gas fired turbines.

Because the VOC BACT level was set using data derived from various source test results, this alternate VOC compliance method provides a fair comparison and represents the best sampling and analysis technique for this purpose at this time. The test results shall be reported with two significant digits.
[Rule 1303(a)(1) - BACT, Rule 1303(b)(2) - Offset]

D82.1 The operator shall install and maintain a CEMS to measure the following parameters:

CO concentration in ppmv
Concentrations shall be corrected to 15 percent oxygen on a dry basis
The CEMS shall be installed and operated no later than 90 days after initial start-up of the turbine, and in accordance with an approved AQMD Rule 218 CEMS plan application. The operator shall not install the CEMS prior to receiving initial approval from AQMD. Within two weeks of the turbine start-up, the operator shall provide written notification to the District of the exact date of start-up.

The CEMS shall be installed and operated to measure CO concentrations over a 15 minute averaging time period.

The CEMS would convert the actual CO concentrations to mass emission rates (lbs/hr) using the equation below and record the hourly emission rates on a continuous basis.

CO Emission Rate, lbs/hr = K Cco Fd[20.9/(20.9% - %O2 d)][(Qg * HHV)/106], where

$K = 7.267 * 10^{-8}$ (lb/scf)/ppm

Cco = Average of four consecutive 15 min. ave. CO concentration, ppm

Fd = 8710 dscf/MMBTU natural gas

$\%O_2$ d = Hourly ave. % by vol. O_2 dry, corresponding to Cco

Qg = Fuel gas usage during the hour, scf/hr

HHV = Gross high heating value of fuel gas, BTU/scf
[Rule 1303(a)(1) - BACT, Rule 218]

D82.2 The operator shall install and maintain a CEMS to measure the following parameters:

NOx concentration in ppmv

Concentrations shall be corrected to 15 percent oxygen on a dry basis.
The CEMS shall be installed and operating no later than 90 days after initial start-up of the turbine and shall comply with the requirements of Rule 2012. During the interim period between the initial start-up and the provisional certification date of the CEMS, the operator shall comply with the monitoring requirements of Rule 2012(h)(2)and 2012(h)(3). Within two weeks of the turbine start-up date, the operator shall provide written notification to the District of the exact date of start-up.

The CEMS shall be installed and operating (for BACT purposes only) no later than 90 days after initial start up of the turbine.
[Rule 2005; Rule 2012]

E193.1 The operator shall upon completion of construction, operate and maintain this equipment according to the following specifications:

In accordance with all mitigation measures stipulated in the final California Energy Commission decision for the 05-AFC-3 project.
[CEQA]

H23.1 This equipment is subject to the applicable requirements of the following rules and regulations:

CONTAMINANT	RULE	RULE/SUBPART
NOx	40CFR60 Subpart	KKKK
SOx	40CFR60 Subpart	KKKK

[40CFR60 Subpart KKKK]

I296.1 This equipment shall not be operated unless the operator demonstrates to the Executive Officer that the facility holds sufficient RTCs to offset the prorated annual emissions increase for the first compliance year of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the first compliance year of operation, the facility holds sufficient RTCs in an amount equal to the annual emission increase.

To comply with this condition, the operator shall prior to the 1st compliance year hold a minimum NOx RTCs of 38,664 lbs/yr. This condition shall apply during the 1st 12 months of operation, commencing with the initial operation of the gas turbine.

To comply with this condition, the operator shall, prior to the beginning of all years subsequent to the 1st compliance year, hold a minimum of 30,222 lbs/yr of NOx RTC's for operation of the gas turbine. In accordance with Rule 2005(f), unused RTC's may be sold only during the reconciliation period for the fourth quarter of the applicable compliance year inclusive of the 1st compliance year.
This condition shall apply to each turbine individually.
[Rule 2005]

K40.1 The operator shall provide to the District a source test report in accordance with the following specifications:

Source test results shall be submitted to the District no later than 60 days after the source test was conducted.
Emission data shall be expressed in terms of concentration (ppmv) corrected to 15 percent oxygen (dry basis), mass rate (lb/hr), and lb/MMCF. In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains/DSCF.
All exhaust flow rate shall be expressed in terms of dry standard cubic feet per minute (DSCFM) and dry actual cubic feet per minute.
All moisture concentration shall be expressed in terms of percent corrected to 15 percent oxygen.
Source test results shall also include the oxygen levels in the exhaust, fuel flow rate (CFH), the flue gas temperature, and the generator power output (MW) under which the test was conducted.
[Rule 1303(a)(1) - BACT, Rule 1303(b)(2) - Offset, Rule 2005]

K67.1 The operator shall keep records in a manner approved by the District, for the following parameter(s) or item(s):

Natural gas fuel use after CEMS certification
Natural gas fuel use during the commissioning period
Natural gas fuel use after the commissioning period and prior to CEMS certification
[Rule 2012]

(SCR/CO Catalyst)

A195.4 The 5 ppmv NH3 emission limit is averaged over 60 minutes at 15% O2, dry basis. The operator shall calculate and continuously record the NH3 slip concentration using the following:

NH3 (ppmv) = [a-b*c/1EE+06]*1EE+06/b

where,
a = NH3 injection rate (lbs/hr)/17(lb/lb-mol)
b = dry exhaust gas flow rate (scf/hr)/385.3 scf/lb-mol)
c = change in measured NOx across the SCR (ppmvd at 15% O2)

The operator shall install and maintain a NOx analyzer to measure the SCR inlet NOx ppmv accurate to plus or minus 5 percent calibrated at least once every twelve months.
The NOx analyzer shall be installed and operated within 90 days of initial start-up.
The operator shall use the above described method or another alternative method approved by the Executive Officer.
The ammonia slip calculation procedures described above shall not be used for compliance determination or emission information without corroborative data using an approved reference method for the determination of ammonia.
[Rule 1303(a)(1) - BACT, Rule 2012]

D12.2 The operator shall install and maintain a(n) flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia.

The operator shall also install and maintain a device to continuously record the parameter being measured.
The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every twelve months.
[Rule 1303(a)(1) - BACT, Rule 2005]

D12.3 The operator shall install and maintain a(n) temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the SCR reactor.

The operator shall also install and maintain a device to continuously record the parameter being measured.
The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every twelve months.
[Rule 1303(a)(1) - BACT, Rule 2005]

D12.4 The operator shall install and maintain a(n) pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches of water column.

The operator shall also install and maintain a device to continuously record the parameter being measured.
The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every twelve months.
[Rule 1303(a)(1) - BACT, Rule 2005]

E179.1 For the purpose of the following condition number(s), continuously record shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour.

Condition Number D12.2
Condition Number D12.3
[Rule 1303(a)(1) - BACT]

E179.2 For the purpose of the following condition numbers, continuously record shall be defined as measuring at least once every month and shall be calculated based upon the average of the continuous monitoring for that month.

Condition Number: D12.4
[Rule 1303(a)(1) - BACT]

E193.1 The operator shall upon completion of construction, operate and maintain this equipment according to the following specifications:

In accordance with all mitigation measures stipulated in the final California Energy Commission decision for the 05-AFC-3 project.
[CEQA]

(Ammonia Storage Tank)

C157.1 The operator shall install and maintain a pressure relief valve with a minimum pressure set at 25 psig.
[Rule 1303(a)(1) - BACT]

E144.1 The operator shall vent this equipment, during filling, only to the vessel from which it is being filled.
[Rule 1303(a)(1) - BACT]

E193.1 The operator shall upon completion of construction, operate and maintain this equipment according to the following specifications:

In accordance with all mitigation measures stipulated in the final California Energy Commission decision for the 05-AFC-3 project.
[CEQA]

(Emergency Fire Pump)

C1.3 The operator shall limit the operating time to no more than 199.99 hours in any one year.

For the purposes of this condition, the operating time is inclusive of time allotted for maintenance and testing
[Rule 1110.2, Rule 1304, Rule 2012]

D12.5 The operator shall install and maintain a(n) non-resettable elapsed meter to accurately indicate the elapsed operating time of the engine.
[Rule 1304, Rule 1470, Rule 2012]

D12.6 The operator shall install and maintain a(n) non-resettable totalizing fuel meter to accurately indicate the fuel usage of the engine.
[Rule 1304, Rule 2012]

B61.1 The operator shall only use diesel fuel containing th3 following specified compounds:

COMPOUND	Range	PPM BY WEIGHT
Sulfur	Less than or equal to	15

[Rule 431.2]

E193.1 The operator shall upon completion of construction, operate and maintain this equipment according to the following specifications:

In accordance with all mitigation measures stipulated in the final California Energy Commission decision for the 05-AFC-3 project.
[CEQA]

E193.2 The operator shall operate and maintain this equipment according to the following requirements:

1. This equipment shall only operate if utility electricity is not available.
2. This equipment shall only be operated for the primary purpose of providing a backup source of power to drive a fire pump.
3. This equipment shall only be operated for maintenance and testing, not to exceed 50 hours in any one year.
4. This equipment shall not be operated under a Demand Response Program (DRP).
5. An engine operating log shall be kept in writing, listing the date of operation, the elapsed time, in hours, and the reason for operation. The log shall be maintained for a minimum of 5 years and made available to AQMD personnel upon request.

[Rule 1110.2]

I296.2 This equipment shall not be operated unless the operator demonstrates to the Executive Officer the facility holds sufficient RTCs to offset the prorated annual emissions increase for the first compliance year of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the first compliance year of operation, the facility holds sufficient RTCs in an amount equal to the annual emissions increase.

To comply with this condition, the operator shall, prior to each compliance year hold a minimum NOx RTCs of 2,097 lbs.

In accordance with Rule 2005(f), unused RTCs may be sold only during the reconciliation period for the fourth quarter of the applicable compliance year inclusive of the 1st compliance year.

[Rule 2005]

K67.2 The operator shall keep records in a manner approved by the Executive Officer, for the following parameter(s) or item(s):

Date of operation, the elapsed time, in hours, and the reason for operation

[Rule 1110.2]

(Section D; Device E32)

K67.3 The operator shall keep records, in a manner approved by the District, for the following parameter(s) or item(s):

For architectural applications where thinners, reducers, or other VOC containing materials are added, maintain daily records for each coating consisting of (a) coating type, (b) VOC content as applied in grams per liter (g/l) of materials used for low-solids coatings, (c) VOC content as applied in g/l of coating, less water and exempt solvent, for other coatings.

For architectural applications where no thinners, reducers, or other VOC containing materials are added, maintain semi-annual records consisting of (a) coating type, (b) VOC content as applied in grams per liter (g/l) of materials used for low-solids coatings, (c) VOC content as applied in g/l of coating, less water and exempt solvent, for other coatings.

[Rule 3004-Periodic Monitoring]

SUN VALLEY ENERGY PROJECT
List of Appendices

Appendix A - SUN VALLEY ENERGY PROJECT
LMS100 PA Hourly Emissions - Normal Operations

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Data:
Standard Conditions: 29.92 inches Hg and 68 degrees Fahrenheit
Emission Factor (lb/MMBTU) = (controlled ppmvd)*(MW)*(1/SMV)*(20.9/5.9)*(Fd)*(1/1E6)
where,
controlled ppmvd = controlled concentration corrected to 15% O2
MW = molecular weight (lb/lb-mol)
SMV = specific molar volume at 68 degrees Fahrenheit = 385.3 dscf/lb-mol
Fd = dry oxygen F-factor for natural gas = 8,710 dscf/MMBTU at 68 degrees Fahrenheit
Emission Rate Uncontrolled = Emission Factor Uncontrolled (lb/MMBTU) * Heat Input (MMBTU/hr)
Emission Rate Controlled = Emission Factor Controlled (lb/MMBTU) * Heat Input (MMBTU/hr)
Uncontrolled Emissions from the CTG:
NOx = 25 ppm @ 15% O2, CO = 100 ppm @ 15% O2, VOC = 4 ppm, PM10 = 0.0066 lbs/MMBTU; SOx = 0.25 grains/100 scf

CO Emissions

Operating Condition Number	Heat Input (MMBTU/hr)	Pollutant Conc. Uncontrolled (ppmvd)	Pollutant Conc. Controlled (ppmvd)	Molecular Weight (lbs/lb-mole)	Specific Molar Volume (dscf/lb-mole)	Dry Fuel Factor (dscf/MMBTU)	Emission Factor Uncontrolled (lb/MMBTU)	Emission Factor Controlled (lb/MMBTU)	Emission Rate Uncontrolled (lb/hr)	Emission Rate Controlled (lb/hr)
100	891.7	100	6	28	385.3	8,710	0.2242	0.0135	199.93	12.00
103	870.8	100	6	28	385.3	8,710	0.2242	0.0135	195.24	11.71
106	823.2	100	6	28	385.3	8,710	0.2242	0.0135	184.59	11.08
109	824.5	100	6	28	385.3	8,710	0.2242	0.0135	184.86	11.09
112	824.6	100	6	28	385.3	8,710	0.2242	0.0135	184.88	11.09
Average	**846.9**									**11.39**

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LMS100 PA Hourly Emissions - Normal Operations

NOx Emissions

Operating Condition Number	Heat Input (MMBTU/hr)	Pollutant Conc. Uncontrolled (ppmvd)	Pollutant Conc. Controlled (ppmvd)	Molecular Weight (lb/lb-mol)	Specific Molar Volume (dscf/lb-mole)	Dry Fuel Factor (dscf/MMBTU)	Emission Factor Uncontrolled (lb/MMBTU)	Emission Factor Controlled (lb/MMBTU)	Emission Rate Uncontrolled (lb/hr)	Emission Rate Controlled (lb/hr)
100	891.7	25	2.5	46	385.3	8,710	0.0921	0.0092	82.11	8.21
103	870.8	25	2.5	46	385.3	8,710	0.0921	0.0092	80.19	8.02
106	823.2	25	2.5	46	385.3	8,710	0.0921	0.0092	75.81	7.58
109	824.5	25	2.5	46	385.3	8,710	0.0921	0.0092	75.92	7.59
112	824.6	25	2.5	46	385.3	8,710	0.0921	0.0092	75.93	7.59
Average	**846.9**									**7.80**

VOC Emissions

Operating Condition Number	Heat Input (MMBTU/hr)	Pollutant Conc. Uncontrolled (ppmvd)	Pollutant Conc. Controlled (ppmvd)	Molecular Weight (lb/lb-mol)	Specific Molar Volume (dscf/lb-mol)	Dry Fuel Factor (dscf/MMBTU)	Emission Factor Uncontrolled (lb/MMBTU)	Emission Factor Controlled (lb/MMBTU)	Emission Rate Uncontrolled (lb/hr)	Emission Rate Controlled (lb/hr)
100	891.7	4	2.0	12	385.3	8,710	0.0038	0.0019	3.43	1.71
103	870.8	4	2.0	12	385.3	8,710	0.0038	0.0019	3.35	1.67
106	823.2	4	2.0	12	385.3	8,710	0.0038	0.0019	3.16	1.58
109	824.5	4	2.0	12	385.3	8,710	0.0038	0.0019	3.17	1.58
112	824.6	4	2.0	12	385.3	8,710	0.0038	0.0019	3.17	1.58
Average	**846.9**									**1.63**

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LMS100 PA Hourly Emissions - Normal Operations

PM10 Emissions

Operating Condition Number	Heat Input (MMBTU/hr)	Emission Factor[1] (lb/MMBTU)	Emission Rate Uncontrolled (lb/hr)	Emission Rate Controlled (lb/hr)
100	891.7	0.0067	6.00	6.00
103	870.8	0.0067	5.86	5.86
106	823.2	0.0067	5.54	5.54
109	824.5	0.0067	5.55	5.55
112	824.6	0.0067	5.55	5.55
Average	**846.9**		**5.70**	**5.70**

SOx Emissions

Operating Condition Number	Heat Input (MMBTU/hr)	Emission Factor[2] (lb/MMBTU)	Emission Rate Uncontrolled (lb/hr)	Emission Rate Controlled (lb/hr)
100	891.7	0.00068	0.606	0.606
103	870.8	0.00068	0.592	0.592
106	823.2	0.00068	0.560	0.560
109	824.5	0.00068	0.561	0.561
112	824.6	0.00068	0.561	0.561
Average	**846.9**		**0.576**	**0.576**

[1] Based on manufacture guarantee of 6 lb/hr at 891.7 MMBTU/hr = 0.00673 lb/MMBTU

[2] Based on a maximum sulfur content of 0.25 grains/100 scf fuel; 1,050 BTU/scf natural gas; and 7,000 grains/lb, and 1 mole S for 2 moles SO_2

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LMS100 PA Hourly Emissions - Normal Operations

NH3 Emissions

Operating Condition Number	Heat Input (MMBTU/hr)	Pollutant Conc. Controlled (ppmvd)	Molecular Weight (lb/lb-mol)	Specific Molar Volume (dscf/lb-mol)	Dry Fuel Factor (dscf/MMBTU)	Emission Factor (lb/MMBTU)	Emission Rate (lb/hr)
100	891.7	5	17	385.3	8,710	0.0068	6.07
103	870.8	5	17	385.3	8,710	0.0068	5.93
106	823.2	5	17	385.3	8,710	0.0068	5.60
109	824.5	5	17	385.3	8,710	0.0068	5.61
112	824.6	5	17	385.3	8,710	0.0068	5.61
Average	**846.9**						**5.76**

Appendix A - SUN VALLEY ENERGY PROJECT
LMS100 PA Hourly Emissions - Start-Up / Shutdown Operations

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Assumptions

Start-up / shutdown events will not significantly afftect SOx and PM10 emissions. Emission rates are assumed to be equal to normal operations

One start-up per hour

Start-Up Emissions

Pollutant	Start-Up Emission Factor (lb/event)[1]	Normal Operations (lb/hr)[2]	Normal Operations (lb/hr)[3]	Start-Up Emissions (lbs/hr)
CO	15.4	12.00	5.00	20.40
NOx	7.0	8.21	3.42	10.42
VOC	2.1	1.71	0.71	2.81
PM10	N/A	N/A	N/A	6.00
SOx	N/A	N/A	N/A	0.606

[1] A start-up event is defined as the first 35 minutes of start-up, per GE specs

[2] The emission rates in this column are assumed to occur for 1 full hour

[3] The emission rates in this column are prorated for the remaining 25 minutes of start-up by multiplying by 25/60

Shutdown Emissions

Pollutant	Shutdown Emission Factor (lb/event)[4]	Normal Operations (lb/hr)[5]	Normal Operations (lb/hr)[6]	Shutdown Emissions (lb/hr)
CO	18.2	12.00	9.80	28.00
NOx	4.3	8.21	6.70	11.00
VOC	1.6	1.71	1.40	3.00
PM10	N/A	6.00	N/A	6.00
SOx	N/A	0.606	N/A	0.606

[4] Emission rates in this column occur during the first 11 minutes of shutdown, per GE specs

[5] Emission rates in this column are assumed to occur for one full hour

[6] Emission rates in this column are pro-rated for the remaining 49 minutes of shutdown by multiplying by 49/60

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Appendix B - SUN VALLEY ENERGY PROJECT
LMS100 PA Monthly Emissions - Commissioning Year

Operating Condition 100	Hours per Month	CO (lbs/hr)	NOx (lbs/hr)	VOC (lbs/hr)	PM10 (lbs/hr)	SOx (lbs/hr)	CO (lbs/month)	NOX (lbs/month)	VOC (lbs/month)	PM10 (lbs/month)	SOx (lbs/month)
Unit 1 Start-Up	40	20.40	10.42	2.81	6.00	0.61	816	417	112	240	24
Unit 1 Commissioning[1]	15	72.60	71.21	2.81	4.01	0.34	1,089	1,068	42	60	5
Unit 1 Normal Operation	368	12.00	8.21	1.71	6.00	0.61	4,416	3,021	629	2,208	223
Unit 1 Shutdown	40	28.00	11.00	3.00	6.00	0.61	1,120	440	120	240	24
Unit 1 Totals	**463**						**7,441**	**4,946**	**904**	**2,748**	**277**
Unit 2 Start-Up	40	20.40	10.42	2.81	6.00	0.61	816	417	112	240	24
Unit 2 Commissioning[1]	15	72.60	71.21	2.81	4.01	0.34	1,089	1,068	42	60	5
Unit 2 Normal Operation	368	12.00	8.21	1.71	6.00	0.61	4,416	3,021	629	2,208	223
Unit 2 Shutdown	40	28.00	11.00	3.00	6.00	0.61	1,120	440	120	240	24
Unit 2 Totals	**463**						**7,441**	**4,946**	**904**	**2,748**	**277**
Unit 3 Start-Up	40	20.40	10.42	2.81	6.00	0.61	816	417	112	240	24
Unit 3 Commissioning[1]	15	72.60	71.21	2.81	4.01	0.34	1,089	1,068	42	60	5
Unit 3 Normal Operation	368	12.00	8.21	1.71	6.00	0.61	4,416	3,021	629	2,208	223
Unit 3 Shutdown	40	28.00	11.00	3.00	6.00	0.61	1,120	440	120	240	24
Unit 3 Totals	**463**						**7,441**	**4,946**	**904**	**2,748**	**277**
Unit 4 Start-Up	40	20.40	10.42	2.81	6.00	0.61	816	417	112	240	24
Unit 4 Commissioning[1]	15	72.60	71.21	2.81	4.01	0.34	1,089	1,068	42	60	5
Unit 4 Normal Operation	368	12.00	8.21	1.71	6.00	0.61	4,416	3,021	629	2,208	223
Unit 4 Shutdown	40	28.00	11.00	3.00	6.00	0.61	1,120	440	120	240	24
Unit 4 Totals	**463**						**7,441**	**4,946**	**904**	**2,748**	**277**
Unit 5 Start-Up	40	20.40	10.42	2.81	6.00	0.61	816	417	112	240	24
Unit 5 Commissioning[1]	15	72.60	71.21	2.81	4.01	0.34	1,089	1,068	42	60	5
Unit 5 Normal Operation	368	12.00	8.21	1.71	6.00	0.61	4,416	3,021	629	2,208	223
Unit 5 Shutdown	40	28.00	11.00	3.00	6.00	0.61	1,120	440	120	240	24
Unit 5 Totals	**463**						**7,441**	**4,946**	**904**	**2,748**	**277**
Total Monthly Emissions (lb/month)							37,205	24,731	4,519	13,741	1,383

[1]From Table 12-Proposed Commissioning Schedule in analysis; totals divided by 5 turbines and divided by 134 hours

Appendix B - SUN VALLEY ENERGY PROJECT
LMS100 PA Monthly Emissions - Non-Commissioning Year

PAGES	PAGE	A/N 450931
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Operating Condition 100	Hours per Month	CO (lb/hr)	NOx (lb/hr)	VOC (lb/hr)	PM10 (lb/hr)	SOx (lb/hr)	CO (lb/month)	NOX (lb/month)	VOC (lb/month)	PM10 (lb/month)	SOx (lb/month)
Unit 1 Start-Up	40	20.40	10.42	2.81	6.00	0.61	816	417	112	240	24
Unit 1 Normal Operations	383	12.00	8.21	1.71	6.00	0.61	4,596	3,144	655	2,298	232
Unit 1 Shutdown	40	28.00	11.00	3.00	6.00	0.61	1,120	440	120	240	24
Unit 1 Totals	**463**						**6,532**	**4,001**	**887**	**2,778**	**281**
Unit 2 Start-Up	40	20.40	10.42	2.81	6.00	0.61	816	417	112	240	24
Unit 2 Normal Operations	383	12.00	8.21	1.71	6.00	0.61	4,596	3,144	655	2,298	232
Unit 2 Shutdown	40	28.00	11.00	3.00	6.00	0.61	1,120	440	120	240	24
Unit 2 Totals	**463**						**6,532**	**4,001**	**887**	**2,778**	**281**
Unit 3 Start-Up	40	20.40	10.42	2.81	6.00	0.61	816	417	112	240	24
Unit 3 Normal Operations	383	12.00	8.21	1.71	6.00	0.61	4,596	3,144	655	2,298	232
Unit 3 Shutdown	40	28.00	11.00	3.00	6.00	0.61	1,120	440	120	240	24
Unit 3 Totals	**463**						**6,532**	**4,001**	**887**	**2,778**	**281**
Unit 4 Start-Up	40	20.40	10.42	2.81	6.00	0.61	816	417	112	240	24
Unit 4 Normal Operations	383	12.00	8.21	1.71	6.00	0.61	4,596	3,144	655	2,298	232
Unit 4 Shutdown	40	28.00	11.00	3.00	6.00	0.61	1,120	440	120	240	24
Unit 4 Totals	**463**						**6,532**	**4,001**	**887**	**2,778**	**281**
Unit 5 Start-Up	40	20.40	10.42	2.81	6.00	0.61	816	417	112	240	24
Unit 5 Normal Operations	383	12.00	8.21	1.71	6.00	0.61	4,596	3,144	655	2,298	232
Unit 5 Shutdown	40	28.00	11.00	3.00	6.00	0.61	1,120	440	120	240	24
Unit 5 Totals	**463**						**6,532**	**4,001**	**887**	**2,778**	**281**
Total Monthly Emissions (lb/month)							32,660	20,006	4,437	13,890	1,403

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Appendix B - SUN VALLEY ENERGY PROJECT
LMS100 PA - 30 Day Averages[1,2] - Commissioning Year

Operating Condition 100	Hours per Month	CO (lb/hr)	PM10 (lb/hr)	VOC (lb/hr)	SOx (lb/hr)	CO (lb/month)	PM10 (lb/month)	VOC (lb/month)	SOx (lb/month)
Unit 1 Startup	40	20.40	6.00	2.81	0.606	816	240	112	24
Unit 1 Commissioning	15	72.60	4.01	2.81	0.338	1,089	60	42	5
Unit 1 Normal Operations	368	12.00	6.00	1.71	0.606	4,416	2,208	629	223
Unit 1 Shutdown	40	28.00	6.00	3.00	0.606	1,120	240	120	24
Unit 2 Startup	40	20.40	6.00	2.81	0.606	816	240	112	24
Unit 2 Commissioning	15	72.60	4.01	2.81	0.338	1,089	60	42	5
Unit 2 Normal Operations	368	12.00	6.00	1.71	0.606	4,416	2,208	629	223
Unit 2 Shutdown	40	28.00	6.00	3.00	0.606	1,120	240	120	24
Unit 3 Startup	40	20.40	6.00	2.81	0.606	816	240	112	24
Unit 3 Commissioning	15	72.60	4.01	2.81	0.338	1,089	60	42	5
Unit 3 Normal Operations	368	12.00	6.00	1.71	0.606	4,416	2,208	629	223
Unit 3 Shutdown	40	28.00	6.00	3.00	0.606	1,120	240	120	24
Unit 4 Startup	40	20.40	6.00	2.81	0.606	816	240	112	24
Unit 4 Commissioning	15	72.60	4.01	2.81	0.338	1,089	60	42	5
Unit 4 Normal Operations	368	12.00	6.00	1.71	0.606	4,416	2,208	629	223
Unit 4 Shutdown	40	28.00	6.00	3.00	0.606	1,120	240	120	24
Unit 5 Startup	40	20.40	6.00	2.81	0.606	816	240	112	24
Unit 5 Commissioning	15	72.60	4.01	2.81	0.338	1,089	60	42	5
Unit 5 Normal Operations	368	12.00	6.00	1.71	0.606	4,416	2,208	629	223
Unit 5 Shutdown	40	28.00	6.00	3.00	0.606	1,120	240	120	24
						lb/month	**lb/month**	**lb/month**	**lb/month**
Total Monthly Emissions (lb/month)						37,205	13,741	4,519	1,383
						lb/day	**lb/day**	**lb/day**	**lb/day**
30-Day Average (lb/day)						1,240	458	151	46

[1] SVEP will be in NOx RECLAIM. As such NOx will be offset with RTCs, and therefore no entries for NOx are included in the table below

Appendix B - SUN VALLEY ENERGY PROJECT
LMS100 PA - 30 Day Averages[1,2] - Non-Commissioning Year

PAGES	PAGE	A/N 450931
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Operating Condition 100	Hours per Month	CO (lb/hr)	PM10 (lb/hr)	VOC (lb/hr)	SOx (lb/hr)	CO (lb/month)	PM10 (lb/month)	VOC (lb/month)	SOx (lb/month)
Unit 1 Startup	40	20.40	6.00	2.81	0.606	816	240	112	24
Unit 1 Commissioning	0	72.60	4.01	2.81	0.606	0	0	0	0
Unit 1 Normal Operations	383	12.00	6.00	1.71	0.606	4,596	2,298	655	232
Unit 1 Shutdown	40	28.00	6.00	3.00	0.606	1,120	240	120	24
Unit 2 Startup	40	20.40	6.00	2.81	0.606	816	240	112	24
Unit 2 Commissioning	0	72.60	4.01	2.81	0.606	0	0	0	0
Unit 2 Normal Operations	383	12.00	6.00	1.71	0.606	4,596	2,298	655	232
Unit 2 Shutdown	40	28.00	6.00	3.00	0.606	1,120	240	120	24
Unit 3 Startup	40	20.40	6.00	2.81	0.606	816	240	112	24
Unit 3 Commissioning	0	72.60	4.01	2.81	0.606	0	0	0	0
Unit 3 Normal Operations	383	12.00	6.00	1.71	0.606	4,596	2,298	655	232
Unit 3 Shutdown	40	28.00	6.00	3.00	0.606	1,120	240	120	24
Unit 4 Startup	40	20.40	6.00	2.81	0.606	816	240	112	24
Unit 4 Commissioning	0	72.60	4.01	2.81	0.606	0	0	0	0
Unit 4 Normal Operations	383	12.00	6.00	1.71	0.606	4,596	2,298	655	232
Unit 4 Shutdown	40	28.00	6.00	3.00	0.606	1,120	240	120	24
Unit 5 Startup	40	20.40	6.00	2.81	0.606	816	240	112	24
Unit 5 Commissioning	0	72.60	4.01	2.81	0.606	0	0	0	0
Unit 5 Normal Operations	383	12.00	6.00	1.71	0.606	4,596	2,298	655	232
Unit 5 Shutdown	40	28.00	6.00	3.00	0.606	1,120	240	120	24
						lb/month	**lb/month**	**lb/month**	**lb/month**
Total Monthly Emissions (lb/month)						32,660	13,890	4,437	1,403
						lb/day	**lb/day**	**lb/day**	**lb/day**
30-Day Average (lb/day)						1,089	463	148	45

[1] SVEP will be in NOx RECLAIM. As such NOx will be offset with RTCs, and therefore no entries for NOx are included in the table below

PAGES	PAGE	A/N 450931
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Appendix C - SUN VALLEY ENERGY PROJECT
LMS100 PA Annual Emissions - Commissioning Year

Operating Condition 100	Hours per Year	CO (lbs/hr)	NOx (lbs/hr)	VOC (lbs/hr)	PM10 (lbs/hr)	SOx (lbs/hr)	CO (lbs/year)	NOX (lbs/year)	VOC (lbs/year)	PM10 (lbs/year)	SOx (lbs/year)
Unit 1 Start-Up	350	20.40	10.42	2.81	6.00	0.61	7,140	3,647	984	2,100	212
Unit 1 Commissioning[1]	134	72.60	71.21	2.81	4.01	0.34	9,728	9,542	377	537	45
Unit 1 Normal Operation	2,634	12.00	8.21	1.71	6.00	0.61	31,608	21,625	4,504	15,804	1,596
Unit 1 Shutdown	350	28.00	11.00	3.00	6.00	0.61	9,800	3,850	1,050	2,100	212
Unit 1 Totals	**3,468**						**58,276**	**38,664**	**6,914**	**20,541**	**2,066**
Unit 2 Start-Up	350	20.40	10.42	2.81	6.00	0.61	7,140	3,647	984	2,100	212
Unit 2 Commissioning[1]	134	72.60	71.21	2.81	4.01	0.34	9,728	9,542	377	537	45
Unit 2 Normal Operation	2,634	12.00	8.21	1.71	6.00	0.61	31,608	21,625	4,504	15,804	1,596
Unit 2 Shutdown	350	28.00	11.00	3.00	6.00	0.61	9,800	3,850	1,050	2,100	212
Unit 2 Totals	**3,468**						**58,276**	**38,664**	**6,914**	**20,541**	**2,066**
Unit 3 Start-Up	350	20.40	10.42	2.81	6.00	0.61	7,140	3,647	984	2,100	212
Unit 3 Commissioning[1]	134	72.60	71.21	2.81	4.01	0.34	9,728	9,542	377	537	45
Unit 3 Normal Operation	2,634	12.00	8.21	1.71	6.00	0.61	31,608	21,625	4,504	15,804	1,596
Unit 3 Shutdown	350	28.00	11.00	3.00	6.00	0.61	9,800	3,850	1,050	2,100	212
Unit 3 Totals	**3,468**						**58,276**	**38,664**	**6,914**	**20,541**	**2,066**
Unit 4 Start-Up	350	20.40	10.42	2.81	6.00	0.61	7,140	3,647	984	2,100	212
Unit 4 Commissioning[1]	134	72.60	71.21	2.81	4.01	0.34	9,728	9,542	377	537	45
Unit 4 Normal Operation	2,634	12.00	8.21	1.71	6.00	0.61	31,608	21,625	4,504	15,804	1,596
Unit 4 Shutdown	350	28.00	11.00	3.00	6.00	0.61	9,800	3,850	1,050	2,100	212
Unit 4 Totals	**3,468**						**58,276**	**38,664**	**6,914**	**20,541**	**2,066**
Unit 5 Start-Up	350	20.40	10.42	2.81	6.00	0.61	7,140	3,647	984	2,100	212
Unit 5 Commissioning[1]	134	72.60	71.21	2.81	4.01	0.34	9,728	9,542	377	537	45
Unit 5 Normal Operation	2,634	12.00	8.21	1.71	6.00	0.61	31,608	21,625	4,504	15,804	1,596
Unit 5 Shutdown	350	28.00	11.00	3.00	6.00	0.61	9,800	3,850	1,050	2,100	212
Unit 5 Totals	**3,468**						**58,276**	**38,664**	**6,914**	**20,541**	**2,066**
Total Annual Emissions (lb/year)							**291,382**	**193,321**	**34,571**	**102,707**	**10,328**

[1]From Table 12-Proposed Commissioning Schedule in analysis; totals divided by 5 turbines

Appendix C - SUN VALLEY ENERGY PROJECT
LMS100 PA Annual Emissions - Non-Commissioning Year

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Operating Condition 100	Hours per Year	CO (lbs/hr)	NOx (lbs/hr)	VOC (lbs/hr)	PM10 (lbs/hr)	SOx (lbs/hr)	CO (lbs/year)	NOX (lbs/year)	VOC (lbs/year)	PM10 (lbs/year)	SOx (lbs/year)
Unit 1 Start-Up	350	20.40	10.42	2.81	6.00	0.61	7,140	3,647	984	2,100	212
Unit 1 Normal Operations	2768	12.00	8.21	1.71	6.00	0.61	33,216	22,725	4,733	16,608	1,677
Unit 1 Shutdown	350	28.00	11.00	3.00	6.00	0.61	9,800	3,850	1,050	2,100	212
Unit 1 Totals	**3,468**						**50,156**	**30,222**	**6,767**	**20,808**	**2,102**
Unit 2 Start-Up	350	20.40	10.42	2.81	6.00	0.61	7,140	3,647	984	2,100	212
Unit 2 Normal Operations	2768	12.00	8.21	1.71	6.00	0.61	33,216	22,725	4,733	16,608	1,677
Unit 2 Shutdown	350	28.00	11.00	3.00	6.00	0.61	9,800	3,850	1,050	2,100	212
Unit 2 Totals	**3,468**						**50,156**	**30,222**	**6,767**	**20,808**	**2,102**
Unit 3 Start-Up	350	20.40	10.42	2.81	6.00	0.61	7,140	3,647	984	2,100	212
Unit 3 Normal Operations	2768	12.00	8.21	1.71	6.00	0.61	33,216	22,725	4,733	16,608	1,677
Unit 3 Shutdown	350	28.00	11.00	3.00	6.00	0.61	9,800	3,850	1,050	2,100	212
Unit 3 Totals	**3,468**						**50,156**	**30,222**	**6,767**	**20,808**	**2,102**
Unit 4 Start-Up	350	20.40	10.42	2.81	6.00	0.61	7,140	3,647	984	2,100	212
Unit 4 Normal Operations	2768	12.00	8.21	1.71	6.00	0.61	33,216	22,725	4,733	16,608	1,677
Unit 4 Shutdown	350	28.00	11.00	3.00	6.00	0.61	9,800	3,850	1,050	2,100	212
Unit 4 Totals	**3,468**						**50,156**	**30,222**	**6,767**	**20,808**	**2,102**
Unit 5 Start-Up	350	20.40	10.42	2.81	6.00	0.61	7,140	3,647	984	2,100	212
Unit 5 Normal Operations	2768	12.00	8.21	1.71	6.00	0.61	33,216	22,725	4,733	16,608	1,677
Unit 5 Shutdown	350	28.00	11.00	3.00	6.00	0.61	9,800	3,850	1,050	2,100	212
Unit 5 Totals	**3,468**						**50,156**	**30,222**	**6,767**	**20,808**	**2,102**
Total Annual Emissions (lb/year)							**250,780**	**151,111**	**33,834**	**104,040**	**10,508**

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Appendix D - SUN VALLEY ENERGY PROJECT
Emergency Fire Pump Emissions

Data:
Standard Conditions: 29.92 inches Hg and 68 degrees Fahrenheit
Manufacturer: Clarke
Model No.: JW6H-UF50
Type of Fuel: No. 2 Diesel w/ 0.05% sulfur compounds by weight
Rated Power: 340 bhp at 2,100 rpm
Engine Design: Lean Burn
Maximum Rated Fuel Consumption: 16.0 gph
No. of Cylinders: 6

Assumptions:
Maximum hours of operation: 199 hours/year
Steady speed, steady load operations

Pollutant	Emission Factor[6] (lb/BHP-hr)	Emission Factor[7] (gm/BHP-hr)	Maximum Rated Power (BHP)	Conversion Factor (gm/lb)	Emission Rate (lb/hr)	Annual Emission Rate[8] (lb/year)	Monthly Emission Rate[9] (lb/month)	30 Day Average[10] (lb/day)
NOx	0.031		340	454	10.540	2097.46	174.79	6
CO		0.45	340	454	0.337	67.06	5.59	0
VOC		0.15	340	454	0.112	22.35	1.86	0
PM10		0.09	340	454	0.067	13.41	1.12	0
SOx		0.0055	340	454	0.0041	0.82	0.07	0

[6] NOx is based on the factor found in Table 3.3-1 of AP-42; NOx = 0.031 lb/bhp-hr.
[7] Provided by the engine manufacturer (Clarke)
[8] Emission rate (lb/hr) multiplied by 199
[9] Emission rate (lb/year) divided by 12
[10] Emission rate (lb/month) divided by 30

Appendix E - SUN VALLEY ENERGY PROJECT
Cooling Tower Emissions

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Data:
Manufacturer: Marley
No. of cells: 5
Drift Loss: 0.0005%
Maximum TDS in Circulating Water: 5,000 mg/l
Circulating Water Rate: 35,500 gpm
Fan Exit Height : 39.09 ft AGL
Exhaust Fan Diameter: 22 ft
PM10 Emissions (lb/hr) = (Maximum TDS)*[(3.785*60)/(454*1000)]*(Circulating Water Rate)*(Drift Loss)
Water Source: Reclaimed/Recycled Water
Tower Dimensions: Deck Height: 27.09 ft AGL; Deck Length: 210.7 ft; Deck Width: 36.67 ft

Assumptions:
Cooling tower emissions based on 3,468 hr/yr operation
100% of TDS in solution is converted to PM10 at a drift loss of 0.0005%

Pollutant	Maximum TDS in circulating water (mg/l)	Circulating Water Rate (gpm)	Drift Loss (percent)	PM10 Emissions (lb/hr)	PM10 Emissions (lb/year)	PM10 Emissions[11] (lb/month)	30 Day Average[12] (lb/day)
PM10	5,000	35,500	0.00050	0.4439	1,539.60	128.30	4

[11] PM10 emissions (lb/year) divided by 12
[12] PM10 emissions (lb/month) divided by 30

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Appendix F - SUN VALLEY ENERGY PROJECT
NOx RTC Calculations

Data:
Operating Schedule (1st Year):
Startups = 350 hours/year
Shutdowns = 350 hours/year
Normal Operations = 2,634 hours/year
Commissioning Period =134 hours

Operating Condition 100	Hours per Year	NOx (lb/hr)	NOx (lb/year) per device	NOx (lb/year) cumulative
CTGs				
Startup	350	10.42	3,647.00	18,235.00
Shutdown	350	11.00	3,850.00	19,250.00
Normal Operation	2,634	8.21	21,625.14	108,125.70
Commissioning	134	71.21	9,542.14	47,710.70
CTG Totals	3,468		38,664.28	193,321.40
Emergency Fire Pump	199	10.54	2,097.46	2,097.46
Total 1st Year Emissions (lb/year)			40,761.74	195,418.86
Offset Ratio			1.00	1.00
1st year RTCs (lb/year)			**40,761.74**	**195,418.86**
2nd year RTCs (lb/year)			**32,319.74**	**153,208.86**

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Appendix G - SUN VALLEY ENERGY PROJECT

Emission Factors[1]

Total Annual Hours of Operation = 3,468 hours
Total Hours of Commissioning = 134 hours
Total Hours During Non-Commissioning = 3,334 hours

Fuel Consumption During the Commissioning Period

Commissioning Schedule	Hours per Phase	Heat Input (MMBTU/hr)	Fuel Heating Value (BTU/scf)	Fuel Consumption (MMscf/hr)	Fuel Consumption per Phase (MMscf)	Cumulative Fuel Cons. during Comm. (MMscf)
Phase 1	20	750	1,050	0.7143	14.2857	14.2857
Phase 2	14	900	1,050	0.8571	12.0000	26.2857
Phase 3	24	2500	1,050	2.3810	57.1429	83.4286
Phase 4	12	4,503	1,050	4.2886	51.4629	134.8914
Phase 5	24	3,500	1,050	3.3333	80.0000	214.8914
Phase 6	40	4,503	1,050	4.2886	171.5429	386.4343

Commissioning Period Emission Factor

Commissioning Schedule	Fuel Consumption per Phase (MMscf)	NOx Emissions per Phase (lb)	CO Emissions per Phase (lb)	NOx EF lb/mmscf	CO EF lb/mmscf
Phase 1	14.2857	9,100	5,500		
Phase 2	12.0000	6,930	4,200		
Phase 3	57.1429	21,000	20,160		
Phase 4	51.4629	4,860	15,300		
Phase 5	80.0000	4,200	1,080		
Phase 6	171.5429	1,620	2,400		
TOTALS	386.4343	47,710	48,640	**123.46**	**125.87**

[1] The heat input values, fuel consumptions, and emissions during each phase of commissioning are for all five CTGs

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Appendix G - SUN VALLEY ENERGY PROJECT
Emission Factors[2]

Annual fuel consumption (AFC) during non-commissioning is calculated as follows:
AFC = (5 CTGs)(891.7 MMBTU/hr)(1 scf/1,050 BTU)(3,334 hr/yr) = 14,156.7 MMscf/yr

Emissions During the Non-Commissioning Period

Total NOx Emissions (lb/yr)	Total CO Emissions (lb/yr)	Total SOx Emissions (lb/yr)	AFC (MMscf/yr)	NOx EF lb/mmscf	CO EF lb/mmscf
153,736	261,280	10,508	14,156.7	**10.8596**	**18.4563**

[2] The total NOx, CO and SOx emissions as well as the AFC are for all 5 CTGs

Emission Factor Determination for Condition A63.1 & A63.2

PM10 EF lb/MMBTU	SOx EF gr/100 scf	VOC EF lb/MMBTU	Grains/lb	Heat Content BTU/scf	PM10 lb/mmscf	SOx lb/mmscf	VOC lb/mmscf
0.0066	0.250	0.0019	7,000	1,050	**6.93**	**0.7143**	**1.9950**

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA

APPLICATION FOR CERTIFICATION FOR THE SUN VALLEY ENERGY PROJECT (SVEP)

DOCKET NO. 05-AFC-3

(Revised 1/29/2007)

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Sacramento, CA 95814-5512
E-mail: docket@energy.state.ca.us

* * * *

In addition to the documents sent to the Commission Docket Unit, also send individual copies of any documents to:

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INTERESTED AGENCIES

None listed as of 3/3/2006

INTERVENORS

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*** Romoland School District**
Roland Skumawitz, Superintendent
25900 Leon Road
Homeland, California 92548

DECLARATION OF SERVICE

I, Joann Gonzales, declare that on January 29, 2007 I deposited copies of the attached Letter from Michael D. Mills/South Coast Air Quality Management District to Robert Worl/CEC dated 1/23/07 Re: Preliminary Determination of Compliance (PDOC) that includes the AQMD's engineering analysis, in the United States mail at Sacramento, CA with first class postage thereon fully prepaid and addressed to those identified on the Proof of Service list above. Transmission via electronic mail was consistent with the requirements of California Code of Regulations, title 20, sections 1209, 1209.5, and 1210.

I declare under penalty of perjury that the foregoing is true and correct.

Joann Gonzales
[signature]